enerPLUS

RESOURCES FUND

ANNUAL
REPORT
2001

the Energy of Enerplus

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Energy

• Enerplus has achieved its success by maintaining a proven business plan, balance and discipline throughout varying economic and commodity price cycles.

Created in 1986, ENERPLUS RESOURCES FUND offers investors the benefits of owning a diversified portfolio of crude oil and natural gas producing properties, without the exploration risks commonly associated with the energy industry. Enerplus invests in mature crude oil and natural gas producing properties with

'85

Enerplus Global Energy Management (EGEM) is created to launch first royalty trust in Canada

'86

Enerplus Resources Fund completes a $9 million IPO and begins operating as Canada's first oil and gas royalty trust

'87

Enerplus Resources Fund initiates Series B and completes a $50 million IPO

'88

Enerplus Resources Fund completes another successful IPO with Series C raising $75 million

'89

Enerplus Resources Fund launches Series D raising $26 million

'90

Enerplus merges Series A, B, C, and D into one fund, Series G and changes to open ended fund

'93

Enerplus Resources Fund completes $17 million rights issue

'94

EGEM acquires contracts to manage two additional trusts Westrock Energy Income Funds I & II

predictable production profiles, long reserve life indices, high cash netbacks, and opportunities for low risk development. The net cash flow from these properties is distributed to Unitholders on a monthly basis, providing investors with a superior investment within the energy sector.

'95

Enerplus and Westrock Funds acquire $68 million in assets

'96

EGEM converts Mark Resources, a $500 million energy company, into EnerMark Income Fund; $180 million raised through equity financings

'97

EnerMark acquires Quest Oil & Gas and concludes a $100 million equity financing

'99

The Enerplus Group raises $51 million through rights issues; purchases Derrick Energy and concludes $27 million financing

'00

The Enerplus Group acquires over $850 million in assets; El Paso Energy acquires EGEM; Enerplus Resources Fund merges with the Westrock Funds and becomes the first Canadian royalty trust to trade on the New York Stock Exchange

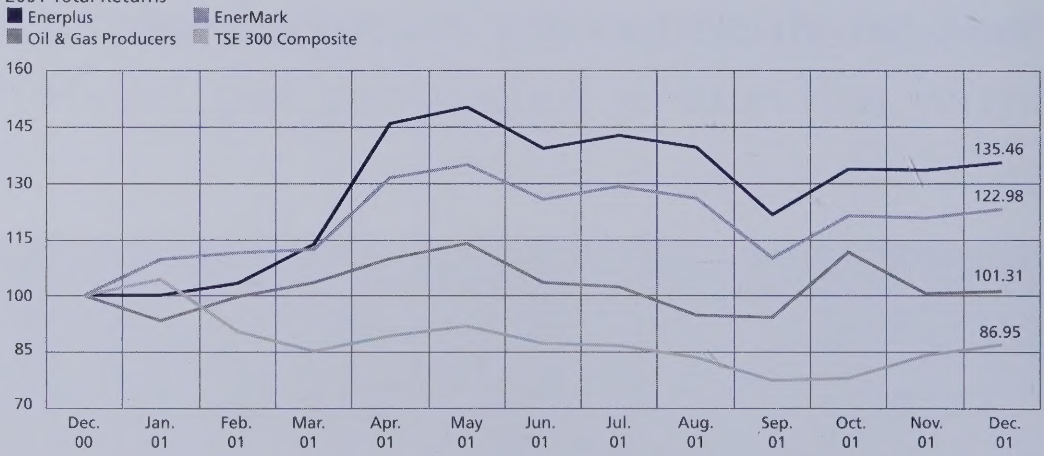
'01

Enerplus Resources Fund and EnerMark Income Fund merge to create the largest conventional oil and gas income fund in North America with an enterprise value of over $2 billion

2001 HIGHLIGHTS

- On June 21, Enerplus Resources Fund merged with EnerMark Income Fund to create North America's largest conventional oil and gas income fund
- Enerplus realized the highest return in the Canadian conventional oil and gas income fund sector, a 34% total return for its Unitholders
- EnerMark Unitholders realized a 22% total return for the year
- Enerplus completed the most active development drilling program in its history, drilling approximately 350 net wells with a 99% success rate
- The Fund's commodity price risk management program generated over $50 million in net proceeds to the Fund

2001 Total Returns



2001 Cash Distribution per Unit

Production Month	Payment Month	Pre-Merger EnerMark (CDN$)	Pre-Merger Enerplus (CDN$)	Post-Merger Enerplus (CDN$)	Enerplus (US$)
January	March	$ 0.09	$ 0.45	$ -	$ 0.29
February	April	0.09	0.45	-	0.29
March	May	0.17	0.90	-	0.58
April	June	0.09	0.52	-	0.34
May	July	-	-	0.48	0.31
June	August	-	-	0.50	0.32
July	September	-	-	0.45	0.29
August	October	-	-	0.40	0.25
September	November	-	-	0.40	0.25
October	December	-	-	0.35	0.22
November	January, 2002	-	-	0.30	0.19
December	February, 2002	-	-	0.25	0.16

2001 SELECTED COMBINED RESULTS

The information contained in the table below reflects the combined results of Enerplus Resources Fund and EnerMark Income Fund for the years indicated as if the combination of the Funds had been effective at January 1, 1997. This information may not be representative of the actual results had the combination occurred on that date. No pro forma adjustments have been made to give effect to the combination of Enerplus and EnerMark for these periods. The information in this table is different from the financial statements and MD&A which account for the combination as a reverse takeover of Enerplus by EnerMark on June 21, 2001 as required by Canadian generally accepted accounting principles.

For the year ended December 31,	2001	2000
OPERATING		
Average Daily Volumes		
Crude oil (bbls/day)	**24,010**	18,118
NGLs (bbls/day)	**4,650**	3,395
Natural gas (Mcf/day)	**203,727**	149,616
Total (BOE/day) (6:1)	**62,615**	46,449
% natural gas	**54%**	54%
Reserve Life Index (years)	**14.0**	13.7

	CDN$		US$	
	2001	2000	**2001**	2000
Average Selling Price Pre-Hedging				
Crude oil (per bbl)	**$ 31.09**	$ 37.08	**$ 20.08**	$ 24.98
NGLs (per bbl)	**32.09**	33.13	**20.72**	22.31
Natural gas (per Mcf)	**5.22**	4.60	**3.37**	3.10
Currency exchange rate ($CDN to $US)	**$ 0.6458**	$ 0.6736	**$ 0.6458**	$ 0.6736
FINANCIAL (combined basis, unaudited) ($000)				
Oil and gas sales before hedging	**$ 713,933**	$ 540,344	**$ 461,058**	$363,974
Proceeds (cost) of hedging	**47,789**	(15,894)	**30,862**	(10,706)
Royalties, net of ARTC	**158,760**	116,505	**102,527**	78,478
Operating costs	**138,218**	86,295	**89,261**	58,128
Netback	**464,744**	321,650	**300,132**	216,662
General and administrative	**14,940**	10,787	**9,649**	7,266
Management fees	**12,066**	8,576	**7,792**	5,777
Interest expense net	**19,287**	20,324	**12,456**	13,690
Capital taxes	**5,248**	3,836	**3,389**	2,583
Restoration and abandonment cash costs	**3,261**	2,782	**2,106**	1,874
Funds flow from operations	**409,942**	275,345	**264,740**	185,472
Cash withheld for debt reduction	**$ 56,100**	$ 18,046	**$ 36,229**	$ 12,156
Debt/funds flow ratio	**1.0x**	1.5x	**1.0x**	1.5x

Number of Units outstanding at December 31, 2001 is 69.5 million and at December 31, 2000 is 40.9 million. All $US amounts shown in the table above were converted using the Canadian to U.S. dollar exchange rate for the applicable periods as indicated within the table.

Positioning

• Enerplus led the Canadian conventional oil and gas sector in total return for 2001

PRESIDENT'S MESSAGE

2001 ACCOMPLISHMENTS

2001 was a very exciting and rewarding year for Enerplus and its Unitholders. Through the merger of EnerMark Income Fund with Enerplus Resources Fund, Enerplus is now the largest conventional oil and gas income fund in North America with a market capitalization of $1.7 billion and an enterprise value of over $2 billion. On a combined basis, Enerplus has achieved record levels of production at 62,615 BOE per day, funds flow from operations of $410 million, and the drilling of 350 net (598 gross) wells with a 99% success rate, while maintaining a healthy established reserve life index in the order of 14 years. Distributions, together with the year over year change in Unit price, have placed Enerplus Unitholders in the

number one position in the conventional oil and gas income fund sector with a total return of 34% for 2001.Likewise, former Unitholders of EnerMark Income Fund who retained their ownership through the merger to year end enjoyed a total return of 22%. We have seen a significant increase in U.S. investor interest in the Fund with our current U.S. ownership in excess of 20% versus under 5% a year ago.

VISION

Our vision for Enerplus is to be the premier oil and gas income fund in North America. To achieve this, we recognize the need to deliver consistent, above average returns to our Unitholders. The strategic pillars upon which we expect to accomplish this objective are based on Enerplus being a successful acquirer, efficient exploiter, low cost operator, and having access to capital, all surrounded by an organizational infrastructure supporting these strategies.

Enerplus has been in operation for over 15 years and during this time has built a reputation of being a leader in the Canadian oil and gas income fund sector. In the past two years, we have taken a number of significant steps forward in distinguishing ourselves in the sector in line with our vision. Our affiliation with El Paso Energy Corporation, the parent Corporation to our manager Enerplus Global Management Corporation, has further enhanced our ability to do business in Canada and access capital in the U.S.

ACQUISITION

In 2000, the Enerplus Group completed nearly one billion dollars of merger and acquisition activities. These transactions were consummated during a time of lower commodity prices somewhat akin to what we are currently experiencing. The result was a doubling of the asset base as well as a further diversification of the asset holdings. In 2001 our acquisition activities were virtually offset by our divestitures. We were disciplined during 2001 in applying our evaluation and bid parameters at a time when there was a certain euphoria surrounding rising commodity prices, especially with respect to natural gas. Our ability to successfully penetrate acquisition markets in 2002 will be predicated upon seller price expectations as well as strategic fits with our business model.

During the last two years, virtually the entire mid-sized Canadian exploration and production ("E&P") based companies have disappeared as a result of merger and acquisition ("M&A") activity. We believe the size we have achieved through this period, together with our expertise in the Western Canadian Sedimentary Basin, places us in a more favourable position to compete not only on large corporate transactions, but on larger sized asset packages which we expect to be forthcoming out of the M&A activities of larger cap E&P companies.

In addition to achieving the size to be successful at acquisitions, we are also taking a proactive (versus reactive) approach to increasing our opportunity for deal flow. On this front, we have been actively approaching industry E&P partners to heighten their awareness of our capacity as well as how we can play a complementary role to their business.

EXPLOITATION

In our industry role as a low risk producer, we do not attempt to develop cutting edge technologies but rather, to extract maximum value from our asset base, we employ proven technologies supplemented by reservoir modeling techniques. Our focus in 2001 was

on the exploitation of the assets we acquired in 2000. As previously mentioned, we participated in the drilling of 350 net wells in addition to numerous facility and enhancement projects. The latter included eight major waterflood projects, sixteen compression installations, and a number of well workover programs. These activities coincide with our underpinning strategy of being an efficient exploiter.

OPERATING EFFICIENCY

With the drilling of 350 net wells, we were able to essentially achieve our targeted production for 2001. As part of our strategy for ensuring we maintain our position as a low cost operator, we have aligned our operations teams to enable them to focus on operations in a particular geographical area and maintain alignment with actual conduct of operations in the field. At the same time, oversight responsibilities at the senior management level ensure consistency in operating standards, dissemination and sharing of information among the various teams, and ensuring that we take advantage of our aggregate buying power as a consumer of supplies and services. In addition, we are employing benchmarking data to improve on the competitiveness and efficiency of our operations on an area by area basis.

ACCESS TO CAPITAL

Over the course of the last two years, the trust sector overall has enjoyed ready access to capital in the Canadian marketplace. Since our listing on the New York Stock Exchange ("NYSE") late in 2000, we have positioned ourselves to have even greater access to capital through the U.S. markets. The interest in Enerplus is illustrated by the increase in U.S. ownership which is currently in excess of 20%. We see two key benefits of this additional access to capital. Firstly, diversification of and increased depth in our access to capital, and secondly, the potential to lower our overall cost of capital. Both of these factors enhance our competitive advantage with respect to acquisition opportunities. Again, we have been proactively communicating with E&P companies to improve their understanding of how we access a different investor appetite (lower risk oil and gas investment with yield orientation) that can efficiently bring capital into the Canadian oil and gas industry.

ORGANIZATION

Finally, with respect to the organizational infrastructure surrounding our strategies, we ensure we have experienced oil and gas personnel in place in order to execute these strategies. Additionally, we monitor responsibility levels, business structures, and technology tools available to ensure we maintain creativity, responsiveness and efficiency in the conduct of our business. We have also realigned the structure of our management contracts to be more performance based as opposed to transactional based, a concept we have carried through to our employee compensation practices to ensure all stakeholders' (Unitholders, manager, and employees) interests are aligned.

Through the merger of EnerMark with Enerplus, a new board of directors has been constituted, chaired by an independent chairman, Mr. Doug Martin, and comprised of a majority of independent board members. The board is charged with, among other responsibilities, the overall strategic direction of the Fund. I wish to thank my fellow board members for their wisdom and guidance in the setting of our strategic direction.

OUTLOOK FOR 2002

As we move into 2002, we've come from a backdrop of volatility in oil and gas prices, exacerbated by global economies in a recessionary mode through the latter half of 2001 and into the first quarter of 2002. As with almost any swing in economic conditions, opportunities are created.

We believe that our opportunities to consummate oil and gas acquisitions will be elevated in the current year. This will be a primary focus for our organization in 2002. We will continue to monitor and evaluate acquisition opportunities as they are brought to the market, however, we will also aggressively pursue internally identified opportunities where we believe we have a high probability of negotiating a successful transaction that fits within our criteria for acquisition.

In addition to targeting value-adding acquisitions, we have also planned another sizeable development drilling and exploitation program for 2002. Our board has approved a $130 million capital spending program exclusive of any acquisition opportunities presented for separate consideration. Our spending for 2002 is targeted 35% to light oil development, 35% to shallow gas development, 15% to medium depth and deep gas development, and 15% to medium and heavy oil development.

While we have planned for the program as referenced, we will be prepared to shift additional capital resources towards acquisition opportunities or, alternatively, conserve our capital resources should a decline in commodity prices occur that reduces the benefits of planned spending below our economic thresholds.

Our recently announced monthly distribution of 20 cents per unit payable March 20th, is indicative of maintainable distribution levels based upon where commodity prices existed during January 2002 and providing some allowance for capital spending. I encourage readers to review our full annual report inclusive of our management's discussion and analysis to gain a more comprehensive view of our activities in 2001 and our direction going forward.

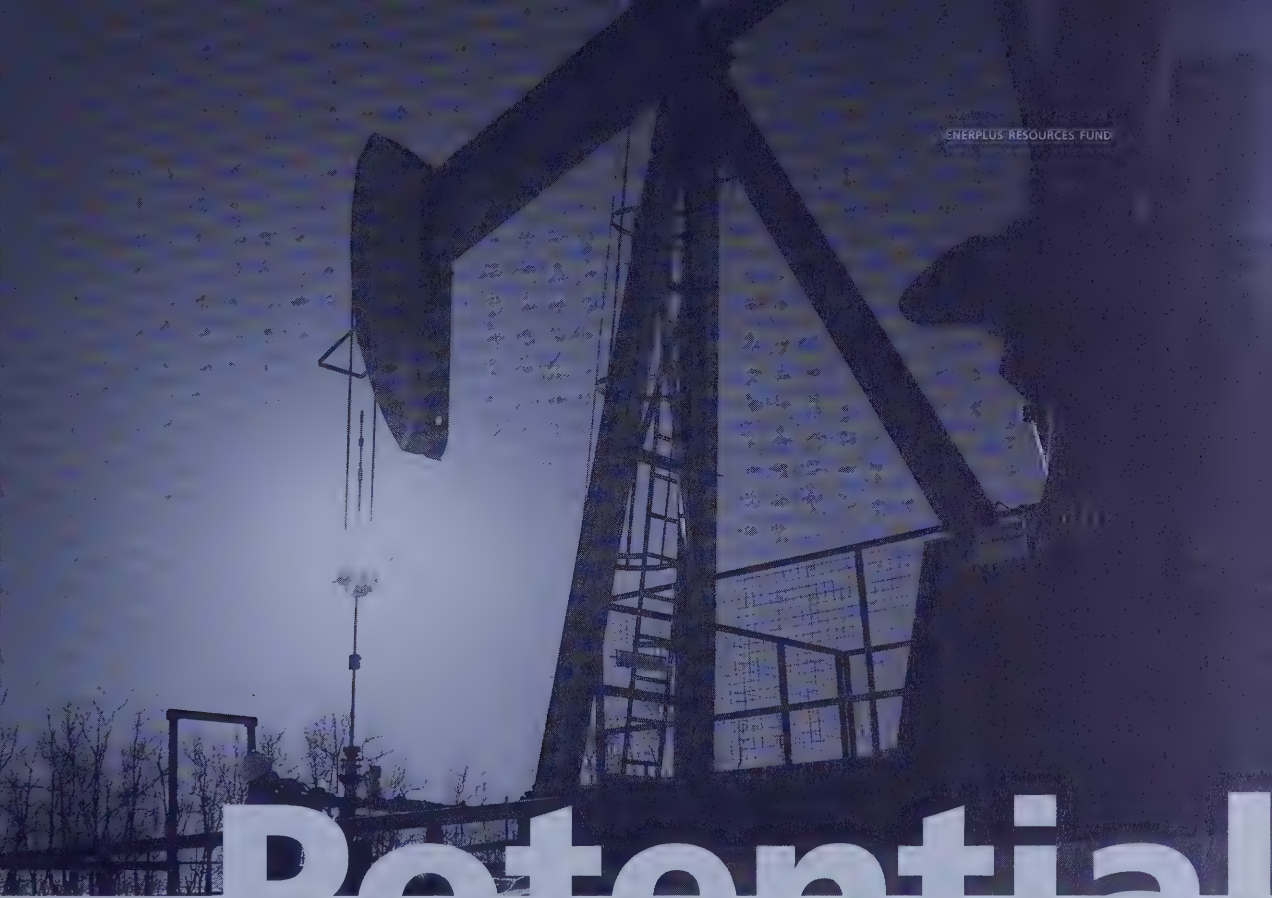
As a final note, I want to thank all of the members of our team here at Enerplus. Through the dedication, expertise and creativity of our team, we have achieved great success and I am confident we will continue to do so in the future.

On behalf of the Board of Directors,

Gordon J. Kerr
President and Chief Executive Officer
March 1, 2002

Enerplus operates approximately 65% of its daily production

Major Properties Combined 2001 Average Daily Production		Crude Oil & NGLs (bbls/day)	Natural Gas (Mcf/day)	Total (BOE/day) (6:1)	Established RLI (years)
1. North West Region	Deep Basin	519	9,501	2,103	9.1
	Progress	891	6,909	2,043	5.5
	Valhalla	470	6,333	1,526	7.4
	Cranberry	83	3,560	676	15.2
2. Central Region	Joarcam	2,170	7,707	3,455	11.1
	Pembina 5 Way/South Buck Lake	2,350	1,506	2,601	29.0
	Pine Creek	274	4,895	1,090	19.4
	Kaybob	419	3,884	1,066	12.4
	Willesden Green	121	2,871	600	7.4
3. East Central Region	Giltedge	1,546	597	1,646	18.6
	Auburndale	752	800	885	4.5
	Hayter	774	2	774	6.0
	Kessler	665	117	685	6.7
	Gleneath	568	162	595	22.8
	Cadogan	531	-	531	6.5
	David	493	93	509	4.4
4. South Central Region	Hanna/Garden Plains	1	10,898	1,817	31.3
	Benjamin	11	9,988	1,676	13.7
	Sylvan Lake	712	3,231	1,251	9.8
	Bashaw	66	6,708	1,184	3.8
	Ferrier	241	3,710	859	9.6
	Harmattan	250	1,780	547	4.9
5. South East Region	Medicine Hat Region	6	27,026	4,510	16.7
	Medicine Hat Glauc "C"	704	1,025	875	17.5
	Jenner	400	1,465	644	8.0
Other		13,643	88,959	28,467	
Total		28,660	203,727	62,615	



Potential

• Enerplus drilled 350 net wells in 2001 with a 99% success rate

PRODUCTION AND OPERATIONS

Enerplus owns and operates the largest and most diverse set of crude oil and natural gas assets of any conventional oil and gas income fund in Canada. These are generally mature assets with predictable production profiles and have above-average reserve life indices (RLI). The properties are located exclusively in the Western Canadian Sedimentary Basin where Enerplus has been active in the oil and gas upstream sector for over 15 years.

The information contained in the following pages presents the Fund's 2001 operational activities on a combined basis as if Enerplus and EnerMark had been combined for the entire year. During 2001, Enerplus produced average daily production volumes of 62,615 BOE/day. This compares favourably with the combined average daily rate of 46,449 BOE/day for 2000 and represents a 35% increase year over year.

These volumes are comprised of liquids (oil and natural gas liquids) production of 28,660 bbls/day and natural gas production of 203.7 MMcf/day. Enerplus successfully maintained production volumes throughout the year as a result of an aggressive development program. The average production rate achieved was slightly below a targeted production of 64,000 BOE/day primarily as a result of project delays experienced throughout 2001 due to demands on suppliers and field services across the industry. The timing of property divestments early in the year also impacted the Fund's annual production volumes.

The Fund operates approximately 65% of its daily production volumes and owns an interest in over 10,000 wells producing from over 250 accumulations and fields. On a percentage basis, daily production volumes were approximately 46% liquids and 54% gas production during 2001. The property and product diversity within the Fund minimizes the risks associated with any single property, area, or commodity. The table on page ten highlights the Fund's major fields organized by regions which represent 55% of the total combined production volumes. The remaining production volumes are from a variety of other operated and non-operated properties.

NORTH WEST REGION

Located along the northern border of British Columbia and Alberta, the Northern Region offers exposure to both light crude oil and liquids rich natural gas through a variety of Triassic to Cretaceous age reservoirs. During 2001, development activities focused on the natural gas reservoirs and included development drilling and facility upgrades totalling $15 million. With over 21 million barrels of oil equivalent (MMBOE) of established reserves attributable to the major properties, further development potential will be pursued in the Deep Basin, Valhalla and Progress natural gas properties as well as the light oil pools at Valhalla and Progress during 2002.

CENTRAL REGION

The area surrounding the city of Edmonton provides a variety of production bases, predominantly weighted to light quality sweet oil and liquids rich natural gas. The Fund's largest producing light oil properties are included in this region and were a significant part of the 2001 development program. Approximately $36 million was spent on the drilling of development wells and facilities during 2001, including additional working interests acquired in the areas of Joarcam, Kaybob and Pembina Five Way. 2002 capital expenditures of approximately $30 million will be focused on increasing light oil production from the major properties where there are over 55 MMBOE of established reserves.

EAST CENTRAL REGION

Located in the heavy oil belt along the Alberta/Saskatchewan border, the East Central Region reservoirs are primarily a compilation of light, medium and heavy oils with approximately 26 MMBOE of established reserves attributed to the major properties. The 2001 capital program in this region was focused on facility improvements in the heavy oil properties and development drilling in the light oil properties. Additional working interests were acquired at Gleneath, Kessler and other smaller properties where operational synergies and development potential were apparent to the Fund. Capital expenditures in the amount of $15 million are planned in this region for 2002 and will be directed primarily to development drilling.

SOUTH CENTRAL REGION

Located just north of Calgary, ownership in this region has increased significantly as a result of acquisitions completed in 2000. Subsequent development activities have not only increased production volumes from the Second White Specks and Deep Foothills natural gas reservoirs, but has resulted in current established reserves of over 52 MMBOE attributable to the major properties. Approximately $34 million of capital was invested in this region in 2001, primarily on development drilling in the Hanna/Garden Plains and Benjamin properties. With further low risk development opportunities available, capital investment in the amount of $18 million is planned for 2002.

SOUTH EAST REGION

The south east region is primarily comprised of shallow natural gas production from the Cretaceous formations but also includes heavy oil from the Glauconite reservoir. The region has been actively developed in 2001 with over 200 natural gas wells drilled in various properties. Production from the region has increased dramatically as a result of this drilling and will continue to grow as a significant number of development opportunities remain in inventory. Capital spending in the amount of $33 million is planned in this region during 2002, targeted primarily on shallow gas development drilling and the optimization of production at the Medicine Hat Glauconite "C" property.

DEVELOPMENT

In 2001, Enerplus focused on developing its inventory of projects stemming from the active acquisitions program completed in 2000. On a combined basis, Enerplus spent approximately $148 million on capital projects and workovers to bring on 10,000 BOE/day in incremental production at an average cost of $14,800 per daily barrel.

This record capital expenditure also created significant value for the Fund by converting proven undeveloped reserves into proven developed producing reserves and also resulted in an increase of approximately 14 MMBOE in new reserves or positive reserve revisions. These additions and revisions offset approximately 61% of the Fund's combined daily production for the year and limited reserve declines to under 3%.

2001 marked the Fund's most active drilling year in its history. Enerplus participated in the successful drilling of 598 gross wells (349.6 net), 8 major waterflood project installations or expansions, 16 compression installation projects to increase natural gas production, numerous facility enhancement and expansion projects and numerous capital workover programs.

Expectations for 2002 are to continue the development programs started in 2001 with a Board approved capital budget of $130 million. Enerplus will monitor commodity prices and project results throughout the year and will adjust its capital spending accordingly.

	Crude Oil		Natural Gas		Dry & Abandoned		Total	
2001 Drilling Activity	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	75	34.7	422	285.0	9	2.3	506	322.0
Saskatchewan	69	17.6	10	6.5	3	1.7	82	25.8
British Columbia	-	-	9	1.3	1	0.5	10	1.8
Total	**144**	**52.3**	**441**	**292.8**	**13**	**4.5**	**598**	**349.6**

Success Rate: 99%

HANNA/GARDEN PLAINS, ALBERTA, OPERATED, WI 80%

Interests in the Hanna/Garden Plains property were acquired in early 2000. The property has become one of our most active areas within the Fund realizing established reserve additions of 61 Bcf net and production growth of 6.4 MMcf/day net during the year.

The property is comprised of over 250 sections of land, of which approximately 40 sections were acquired in 2001 through Crown Land Sales and various swap arrangements with partners. Upon becoming operator of the property in 2000, the Fund commenced aggressive development of the Second White Specks natural gas zone with a program that continued throughout 2001.

Enerplus drilled and tied-in 94 wells in 2001 and tied-in 11 additional wells from 2000 which were awaiting expansion of the gathering system before being placed on production. As a result of our successful development efforts, current net production from this low decline, sweet natural gas property is 13.4 MMcf/day making it the Fund's second largest natural gas property. Hanna/Garden Plains has a 31 year reserve life index. Continued development is planned during 2002 with up to 75 additional wells scheduled for drilling in the latter half of 2002. These activities are expected to further increase production from this pool.

PEMBINA FIVE WAY, ALBERTA, OPERATED, WI 100%

Production optimization of the Pembina Five Way property continued throughout 2001 resulting in approximately 700 bbls/day of incremental production and 2.0 MMbbls of established reserve additions. An 18 well infill drilling program was completed in the second and third quarters of 2001 to increase light oil production from the Cardium formation. The waterflood facilities were expanded in the fourth quarter to optimize production from both the newly drilled wells and existing wells.

Production potential from the area was also increased by refracture stimulating the Cardium formation in 11 wells. Production volumes are currently 2,200 BOE/day net to the Fund. Pembina Five Way has a 29 year reserve life index.

Enerplus is evaluating the results of its 2001 capital initiatives in this area and will continue to seek projects which will increase production from existing wells and take advantage of available processing capacity resulting from the 2001 facility expansion program. Additional drilling will be considered in the latter half of 2002 as part of the ongoing reservoir optimization program.

GLENEATH, SASKATCHEWAN, OPERATED, WI 81%

In early 2001, Enerplus recognized Gleneath had significant upside development potential and pursued an aggressive acquisition and development program that added over 500 bbls/day net and paved the way for significant follow up opportunities in 2002.

The Gleneath property is a large, mature waterflood unit that produces light crude oil from the Viking formation with a 23 year reserve life index. In early 2001, Enerplus realized additional production potential in this property and undertook a proactive approach to acquire additional working interests. These activities resulted in the successful acquisition of three separate blocks totaling a 34.3% working interest producing 280 bbls/day. With these acquisitions completed, Enerplus initiated its development program in the third quarter of 2001 and a total of 13 wells were drilled in the Unit along with one non-Unit well. In addition to this infill drilling, 20 producing oil wells were refracture

stimulated during the year. These projects resulted in a net incremental production rate of 260 bbls/day of light crude oil. The waterflood recovery scheme was also enhanced with the conversion of four wells to water injector wells.

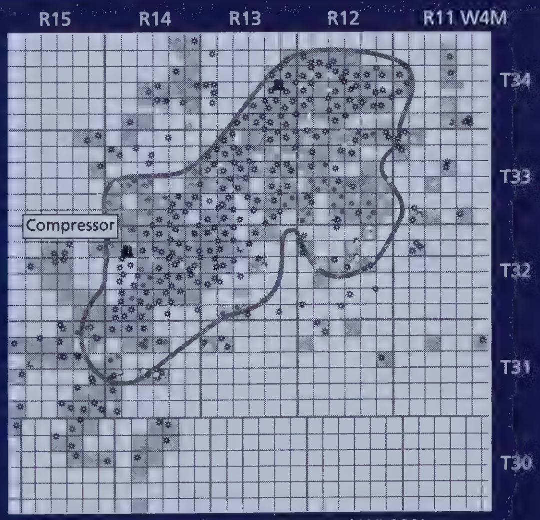
The success of the 2001 development program has provided strong technical evidence that additional upside is available in this property. The capital program for 2002 includes provision for the refracture stimulation of 48 existing wells throughout the year and the drilling of 10 additional Viking oil wells. This activity is expected to add approximately 350 bbls/day of incremental oil production net to the Fund.

MEDICINE HAT BANTRY, ALBERTA, OPERATED, WI 95%

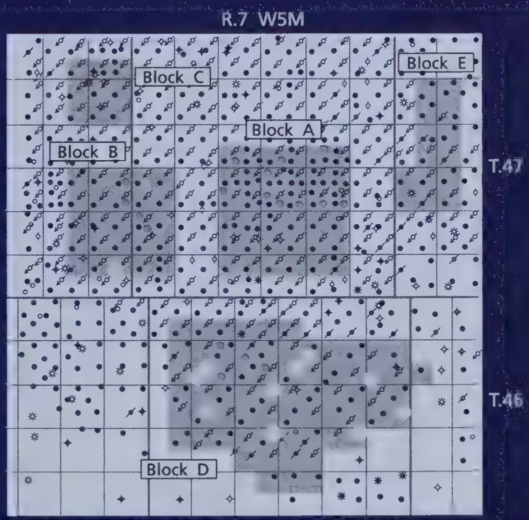
Enerplus continued its successful infill drilling program in 2001, expanding facilities and adding 4.2 MMcf/day of natural gas production with further infill drilling planned for 2002.

Enerplus continued to develop this shallow natural gas area in 2001 with a 27 well drilling program completed in the second quarter and a 66 well drilling program completed in the fourth quarter. In conjunction with this infill drilling, compression capacity was expanded by 8 MMcf/day in the second quarter to handle the incremental production anticipated from the fourth quarter infill program. All wells were successfully drilled in 2001 with the majority of the wells tied-in and brought on stream in January 2002. Net production from this pool was 12.1 MMcf/day at year end and has been increased to 15.0 MMcf/day at the end of February 2002.

Enerplus plans to drill 37 additional wells in the fourth quarter of 2002 to further develop this property.



Hanna/Garden Plains, Alberta Operated WI 80%
• 2002 Program • Spring 2001 • Fall 2001



Pembina Five Way, Alberta Operated WI 100%
• 2001 Cardium infill oil wells ⊙ 2001 Cardium re-fracs

MEDICINE HAT SUN VALLEY, ALBERTA, OPERATED, WI 100%

Enerplus continued its successful development drilling program, expanded facilities and refracture stimulated numerous wells to add 3.1 MMcf/day net of natural gas production.

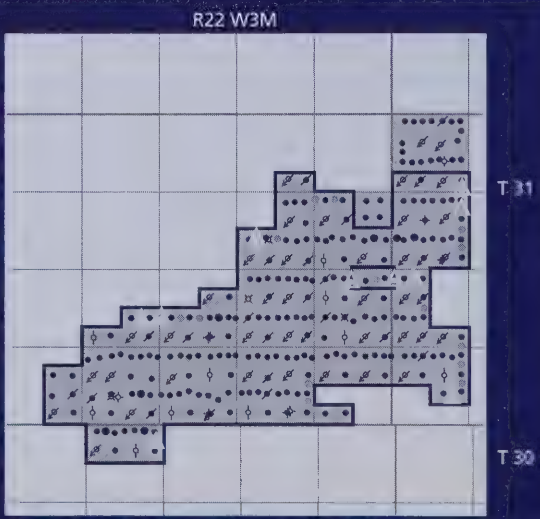
Enerplus succeeded in improving the natural gas production from this Milk River shallow natural gas zone asset during 2000. Based on this success, the Fund initiated development plans in 2001 to infill drill and expand compression capacity to develop an additional 3 MMcf/day of natural gas production. The compression expansion was initiated and completed in the third quarter followed with the refracture stimulation of 17 existing wells. Along with these workovers, Enerplus successfully drilled 45 additional infill wells, which were tied in and placed on-stream in December. Incremental production from this project is approximately 3.1 MMcf/day.

In addition to the production increase, a total of 15.8 Bcf of natural gas reserves were added to the proven developed producing category as a result of the 2001 capital program. Development drilling of 25 additional wells is scheduled for 2002 along with 20 refracs of existing wells to further optimize the production from the property.

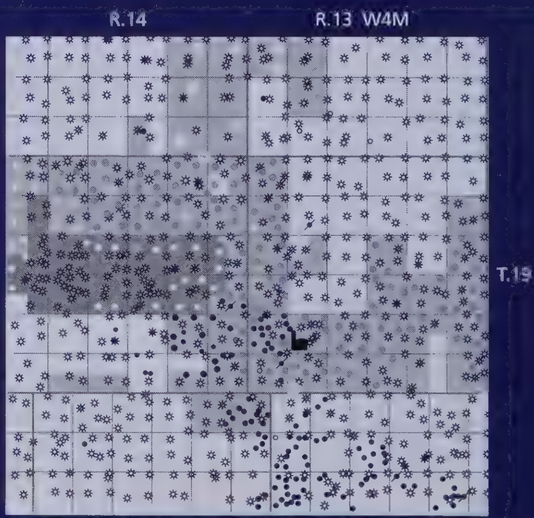
MEDICINE HAT GLAUCONITE C POOL, ALBERTA, OPERATED, WI 72%

Enerplus successfully organized a waterflood unit, implemented waterflood operations and acquired additional interest in this significant oil pool to add production of over 600 BOE/day net to the Fund.

Following the purchase of our 28% working interest in 1998, Enerplus set out to optimize the recovery of the oil from this pool and achieved the first step of



Gleneath, Saskatchewan Operated WI 81%
△ 2002 Infill wells • 2001 infill wells



Medicine Hat Bantry, Alberta, Operated WI 95%
• 2001 shallow gas infill wells ◉ 2002 Bow Island wells
• 2002 shallow gas infill wells

unitizing the pool in 2001. Sixty percent of the pool was unitized early in the year and shortly thereafter, a secondary waterflood recovery scheme was implemented.

With the construction of the waterflood facilities completed in the first half of 2001 water injection in the reservoir has been initiated. The waterflood recovery program is projected to add another 6% to 8% (12-16 million barrels) of recoverable crude oil from this pool.

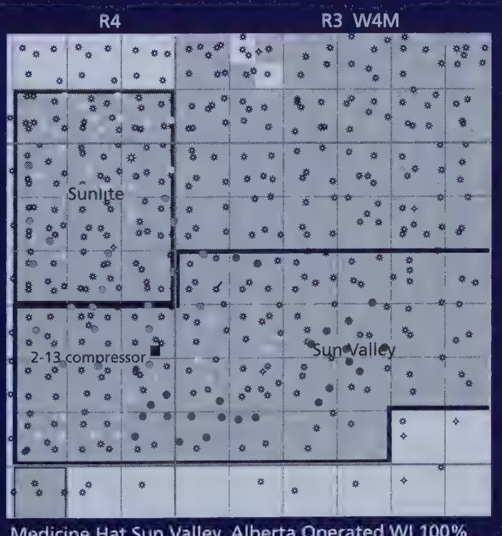
Subsequent to year end, Enerplus concluded the purchase of a partner's interest in both the Unit and non-Unit portions of the pool. The acquired interests provide incremental production of approximately 600 BOE/day to the Fund. With the implementation of the waterflood in 2001, the Fund anticipates production will increase significantly in 2002 as the pool responds to the water injection.

BENJAMIN, ALBERTA, NON-OPERATED, WI 20%

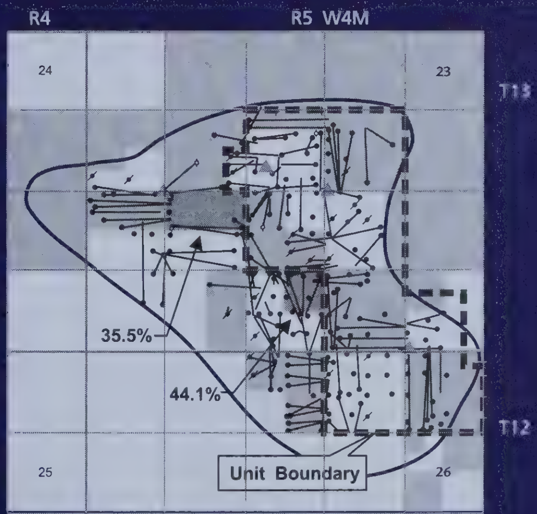
Further development of this deep foothills natural gas property occurred during 2001, with one well successfully drilled and tied-in and the completion of a 47 km pipeline extension to take the production to processing facilities at Ram River.

The successful natural gas well tested at a combined total rate of 20 MMcf/day from three thrust sheets. Placed on-stream in November, the well has added incremental production of 15 MMcf/day (3.0 MMcf/day net) to the Fund.

The natural gas production from the Benjamin area was tied-in to the Ram River and Strachan natural gas plants through the completion of a 47 km pipeline in July of 2001. Additional processing capability was also added to ensure that future gas development from this pool would not be flow restricted. Current



Medicine Hat Sun Valley, Alberta Operated WI 100%
2000 infill wells • 2001 infill wells 2002 infill wells



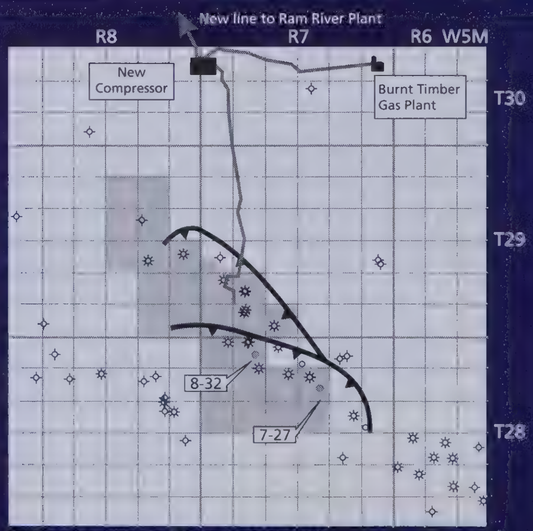
Medicine Hat Glauc. C Pool, Alberta Operated WI 72%
Makeup water plant Battery Acquired Q3

natural gas production from the Benjamin pool is 11.2 MMcf/day net to the Fund. The Operator has proposed two additional wells that will be drilled in 2002 and are expected to add combined production of 3 MMcf/day net to the Fund.

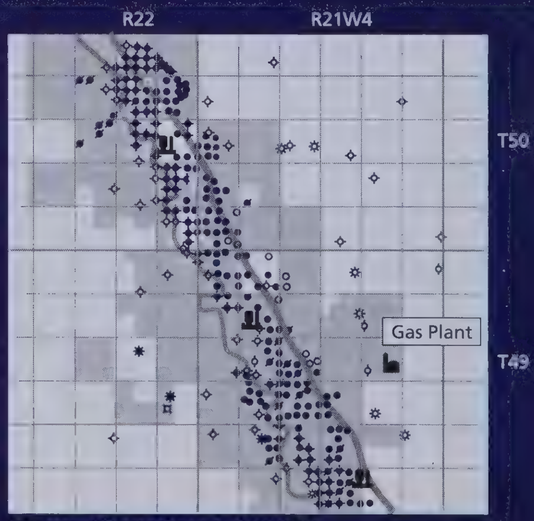
JOARCAM, ALBERTA, OPERATED, WI 80%

Upon the completion of a six-well infill drilling program early in 2001, a reservoir and geological analysis was conducted revealing additional infill drilling potential in this property. As a result, an extensive capital program has been planned for 2002 which will increase production by approximately 50% at Joarcam, the Fund's largest crude oil property. Current production from this pool is 3,200 BOE/day comprised of approximately 2,200 bbls/day of crude oil and natural gas liquids and 6.0 MMcf/day of natural gas net to the Fund.

The reservoir study indicated that additional infrastructure would be required to handle the production from additional infill drilling and plans were developed in the fourth quarter of 2001 to upgrade and expand the gathering system and associated facilities. The 2002 capital program for this area is estimated at $21 million and constitutes the Fund's largest capital expenditure for 2002. The program will consist of a major facility and infrastructure expansion at the north end of the property. This facility work will provide the processing capacity for the 18 well infill drilling program as well as capacity for the existing wells in the area that are not currently optimized. It is anticipated that the facility work will be completed and that 11 of the 18 wells will be drilled and tied-in by the second quarter of 2002. The balance of the wells are expected to be drilled and tied-in by the later half of 2002. Total incremental production from the project is expected to be 1,700 BOE/day.



Benjamin, Alberta Operated WI 20%
• 2002 locations ✲ 2001 location



Joarcam, Alberta Operated WI 80%
• 2001 Viking infill oil wells ○ 2002 Viking infill oil wells

ACQUISITIONS AND DIVESTMENTS

Enerplus is well positioned to capture an increasingly attractive acquisition market in 2002. The Fund reviewed a large number of acquisition opportunities during 2001, acquiring only $85 million in producing oil and natural gas properties in core areas during the year. This was approximately the same value of the properties divested during the year. The high commodity price environment for much of 2001 created a high priced acquisition market, and Enerplus found it difficult to match the prices being paid for assets while at the same time adhering to its disciplined acquisition criteria. As commodity prices have fallen, however, acquisition opportunities are improving and Enerplus is well positioned to capture an increasing share. Enerplus has a strong balance sheet and an experienced acquisitions team with an excellent knowledge of the Western Canadian Sedimentary Basin.

Consolidation occurred at a record pace in the Canadian oil and natural gas industry during 2001 as U.S. buyers drove gas-oriented company valuations to unprecedented levels. This activity was a continuation of the strong merger and acquisition activity seen in 2000 and left the industry markedly different from what it was two years ago. Many of the junior and mid-cap exploration and production ("E&P") companies disappeared through takeover activity. Today, a new model for the Canadian energy sector has emerged in which the royalty trusts, and specifically Enerplus, have assumed a role as the new mid-cap players in the industry.

Royalty trusts such as Enerplus offer investors an efficient opportunity for extracting value from the maturing Western Canadian Sedimentary Basin. Enerplus maintains a low cost of capital by focusing on mature, predictable long life properties that generate strong cash flow for Unitholders. This focus complements an E&P company's strategy as it provides a market for mature properties and the opportunity for the E&P company to re-deploy proceeds from property sales towards higher risk, higher return exploration that will satisfy their higher cost of capital requirements.

Enerplus attempts to match its acquisition and development strategy with the cyclical nature of oil and natural gas prices. During periods of high commodity prices, Enerplus will emphasize internal development projects that provide better economic return to Unitholders than the relatively high priced acquisition market. The year 2001 was such a period, and Enerplus spent $148 million on development projects and drilled approximately 350 net wells. In comparison, during periods of low commodity price cycles, Enerplus searches aggressively for acquisition opportunities that meet or exceed our criteria. Entering 2002, there is evidence that there will be a greater number of quality assets offered for sale as companies rationalize their property portfolios and strengthen their balance sheets after the high activity levels seen during the last two years.

Enerplus focuses its acquisition efforts on properties with the following attributes:

- Mature assets with a long history of performance
- Long life reserve indices
- Attractive, low-risk, low-capital development opportunities
- High proportion of proven reserves
- Located in areas where Enerplus enjoys a competitive advantage

Enerplus focuses its divestment efforts on smaller, marginal properties with production, reserve or operational issues which can be sold above book value.

During 2001, Enerplus and EnerMark, on a combined basis, acquired and divested of approximately the same amount of crude oil and natural gas reserves and daily production. The positive results of this activity saw the Fund's working interest percentage increase in core areas while those in non-core areas were reduced.

2001 Acquisition & Divestment Summary - Combined Basis	Acquired	Divested	Net
Production (BOE/day)	3,025	2,901	124
Cost per Daily Producing BOE	$ 28,100	$ 29,645	
Reserves (MBOE)	10,692	11,194	(502)
Cost Per BOE	$ 7.95	$ 7.68	
Capital ($million)	$ 85	$ 86	$ 1

2001 Acquisitions

During 2001, Enerplus and EnerMark, on a combined basis, invested approximately $85 million on property acquisitions. The focus was to increase reserves in core areas and to buy new properties that meet the criteria previously stated. Enerplus increased its ownership in eight core areas including Medicine Hat, Hanna/Garden Plains, Kaybob, Ferrier, Joarcam, and Gleneath. This 2001 acquisition activity added established reserves of 6.1 MMbbls of liquids and 27.7 Bcf of natural gas, and production volumes of 1,272 bbls/day of liquids and 10.5 MMcf/day of gas. The average acquisition price was approximately $7.95 per BOE of established reserves, and $28,100 per BOE per day.

		Crude oil bbls/day	Natural gas Mcf/day	NGLs bbls/day	Total BOE/day
Daily Production:	Enerplus Jan. - Jun.	157	70	2	171
	EnerMark Jan. - Jun.	125	75	1	137
	Enerplus Jul. - Dec.	791	10,382	196	2,717
	Total	**1,073**	**10,527**	**199**	**3,025**

		Crude oil Mbbl	Natural gas MMcf	NGLs Mbbl	Total MBOE
Reserves:	Enerplus Jan. - Jun.	1,311	238	17	1,368
Proven	EnerMark Jan. - Jun.	111	69	2	121
	Enerplus Jul. - Dec.	3,462	24,312	491	8,005
	Total	**4,884**	**24,619**	**510**	**9,494**
Established	Enerplus Jan. - Jun.	1,509	274	20	1,575
	EnerMark Jan. - Jun.	120	79	2	137
	Enerplus Jul. - Dec.	3,904	27,306	525	8,980
	Total	**5,533**	**27,659**	**547**	**10,692**

Note: Established reserves are defined as proven reserves plus 50% of probable reserves.

2001 Divestments

In addition to our acquisition program, Enerplus manages its asset base through an effective program of property rationalization designed to enable the Fund to capture value for smaller, marginal properties which have production, reserve or operational issues. The divestment of many non-core assets was well timed with the commodity price cycle resulting in the sale of 62 properties in 2001. In total, approximately $86 million was received on the sale of 11.2 MMBOE of established reserves. Combined daily production from these properties was approximately 2,900 BOE per day. The combined average selling price was approximately $7.68 per BOE of established reserves, and $29,645 per BOE per day.

		Crude oil bbls/day	Natural gas Mcf/day	NGLs bbls/day	Total BOE/day
Daily Production:	Enerplus Jan. - Jun.	410	2,169	62	834
	EnerMark Jan. - Jun.	336	1,552	61	656
	Enerplus Jul. - Dec.	857	3,251	12	1,411
	Total	**1,603**	**6,972**	**135**	**2,901**

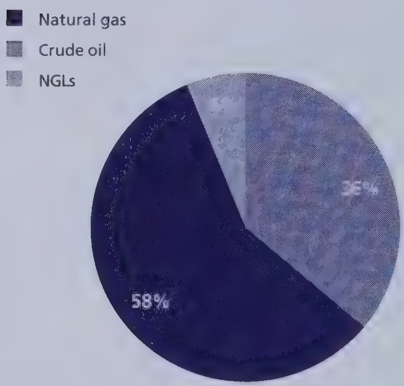
		Crude oil Mbbl	Natural gas MMcf	NGLs Mbbl	Total MBOE
Reserves:					
Proven	Enerplus Jan. - Jun.	996	5,689	257	2,201
	EnerMark Jan. - Jun.	857	8,443	264	2,528
	Enerplus Jul. - Dec.	3,306	8,534	80	4,689
	Total	**5,159**	**22,666**	**601**	**9,418**
Established	Enerplus Jan. - Jun.	1,102	6,560	277	2,472
	EnerMark Jan. - Jun.	1,061	8,524	283	2,765
	Enerplus Jul. - Dec.	3,909	11,723	94	5,957
	Total	**6,072**	**26,807**	**654**	**11,194**

Enerplus plans to continue to actively manage its portfolio by focusing on acquisitions in areas where there are competitive advantages as well as to divest of undesirable properties outside of our strategic focus.

RESERVES

Enerplus strives to maintain long-life reserves to ensure sustainable distributions for its Unitholders. Reserves are added primarily through accretive acquisitions, but are also added through low risk development of existing properties. During high commodity price cycles, as seen in 2001, the Fund emphasized development versus acquisition. Through such development drilling and the associated positive reserve revisions, Enerplus added 14 million barrels of established reserves on a combined basis in 2001. This offset 61% of the reserve declines associated with 2001 combined production of 22.8 MMBOE for the year. The net reserve reduction was less than 3% even though acquisitions were offset by dispositions.

Established Reserves December 31, 2001



Enerplus' reserves of crude oil, natural gas and NGLs have been evaluated by Sproule Associates Limited. This firm of independent petroleum engineers has evaluated year end reserves representing 83% of the Fund's total value (discounted at 12%). All evaluations of future net production revenues set forth in the tables are stated without provision for income taxes, general and administrative costs and management fees. Probable reserves and values have been reduced by a factor of 50% to account for risk.

Established reserves (proven plus 50% probable) at year end 2001 have been estimated at 113.7 million barrels of oil, 1,081 billion cubic feet of natural gas and 18.5 million barrels of natural gas liquids for a total of 312.4 million barrels of oil equivalent based on a natural gas to oil conversion of 6:1. Natural gas reserves represent 58% of the Fund's established reserves.

Enerplus follows the Canadian practice of reporting gross production and reserve volumes, which are prior to the deduction of royalties and similar payments. In the U.S., production and reserve volumes are reported after deducting these amounts. The Canadian practice of using escalating prices and costs when estimating the quantities of reserves is also followed by Enerplus. In the U.S., reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report. Enerplus also follows the Canadian practice of using "Established Reserves", which include proved reserves and the probable reserves portion that has been reduced by a risk factor of 50%. As a consequence, our production volumes and reserve estimates may not be comparable to those made by U.S. companies.

Combined Reserves Summary	Crude oil Mbbl	Natural gas MMcf	NGLs Mbbl	Total MBOE
Total established reserves as at December 31, 2000	122,114	1,085,942	18,696	321,800
Proven, producing	86,770	722,692	13,685	220,904
Proven, non-producing	8,077	228,441	2,429	48,579
Total proven	94,847	951,133	16,114	269,483
Total probable at 50%	18,821	130,345	2,337	42,882
Total established reserves at December 31, 2001	**113,668**	**1,081,478**	**18,451**	**312,365**

	Crude oil MMbbl		Natural gas Bcf		NGLs MMbbl		Total MMBOE		Established
Combined Reserves Reconciliation	Prov.	Prob.	Prov.	Prob.	Prov.	Prob.	Prov.	Prob.	MMBOE
EnerMark Reserves at Dec. 31, 2000	57.2	31.1	655.4	183.5	11.4	3.0	177.8	64.7	210.2
Enerplus Reserves at Dec. 31, 2000	44.2	10.3	298.7	80.1	5.6	0.4	99.6	24.0	111.6
Combined Opening at Dec. 31, 2000	**101.4**	**41.4**	**954.1**	**263.6**	**17.0**	**3.4**	**277.4**	**88.7**	**321.8**
Acquisitions	4.9	1.3	24.6	6.0	0.5	0.1	9.5	2.4	10.7
Divestments	(5.2)	(1.8)	(22.7)	(8.2)	(0.6)	(0.1)	(9.5)	(3.3)	(11.2)
Production	(8.8)	-	(74.4)	-	(1.7)	-	(22.9)	-	(22.9)
Drilling, Develop., Revisions	2.5	(3.3)	69.5	(0.7)	0.9	1.3	15.0	(2.0)	14.0
Reserves at December 31, 2001	**94.8**	**37.6**	**951.1**	**260.7**	**16.1**	**4.7**	**269.5**	**85.8**	**312.4**

Present Worth of Production Revenue ($millions) (including ARTC)	10%	12%
Total combined established reserves at December 31, 2000	$ 2,320.4	$ 2,141.2
Proven, producing	1,377.0	1,257.1
Proven, non-producing	249.3	219.3
Total proven	1,626.3	1,476.4
Probable @ 50%	159.1	133.9
Total established reserves at December 31, 2001	**$ 1,785.4**	**$ 1,610.3**

Net Asset Value ($millions, except per Unit amount)	10%	12%
Present value of established reserves at December 31, 2001	$ 1,785.4	$ 1,610.3
Undeveloped acreage and seismic (acreage valued at $50/acre)	24.3	24.3
Bank debt	(412.6)	(412.6)
Working capital excluding distributions to Unitholders	25.7	25.7
Net asset value	**$ 1,422.8**	**$ 1,247.7**
Net asset value per Unit (1)	**$ 20.46**	**$ 17.94**

(1) based on 69.532 million Units outstanding as at December 31, 2001

PRICING ASSUMPTIONS

The present value of future cash flow at December 31, 2001, was based upon crude oil and natural gas pricing assumptions prepared by Sproule Associates Limited. These forecasts are adjusted for reserve quality, transportation charges and the provisions of any applicable sales contracts. The base reference prices and exchange rate used by Sproule are as follows:

	Crude oil		Natural gas	
Year	WTI Cushing Oklahoma $US/bbl	Light Crude [1] Edmonton $CDN/bbl	30 day spot Plant Gate Price $CDN/Mcf	$CDN/$US Exchange Rate
2002	19.90	29.86	3.63	0.635
2003	20.64	30.96	4.18	0.635
2004	21.12	31.67	4.19	0.635
2005	21.44	32.15	4.18	0.635
2006	21.76	32.65	4.25	0.635

Prices escalated at a rate of 1.5% per year thereafter, exchange rate held constant.

[1] Edmonton refinery postings for 40° API, 0.4% sulphur content crude

UNDEVELOPED LAND

During 2001, the Fund aggressively pursued the monetization of undeveloped lands acquired through previous corporate acquisitions, most notably the lands acquired from Cabre Exploration. As a result of this aggressive program, a total of 265,000 net acres (550,000 gross) or approximately one third of the undeveloped land available at the beginning of the year, were monetized either through sales or farmouts.

A total of 124 wells were committed to be drilled through farmout or pooling arrangements during 2001. These arrangements resulted in 24 producing wells, 62 wells that are now cased and standing, 15 dry holes and the identification of 23 future drilling locations all at no cost for the Fund.

The total value realized from undeveloped land sales and farmouts in 2001 is estimated to be over $14 million. Additional value may be realized over time from the future drilling locations earned on overriding royalty interests or better than expected production from new wells. Enerplus also identifies and develops low risk development drilling locations on undeveloped land which further increases the value associated with the remaining undeveloped land.

Land Inventory at Dec. 31, 2001	Developed Acres		Undeveloped Acres		Royalty Acres
	Gross	Net	Gross	Net	Net
Alberta	2,410,768	806,072	820,008	408,579	693,265
British Columbia	217,967	47,010	118,683	51,505	158,023
Saskatchewan	153,335	79,865	36,559	25,595	136,911
Other	695	189	617	617	2,665
Total	**2,782,765**	**933,136**	**975,867**	**486,296**	**990,864**

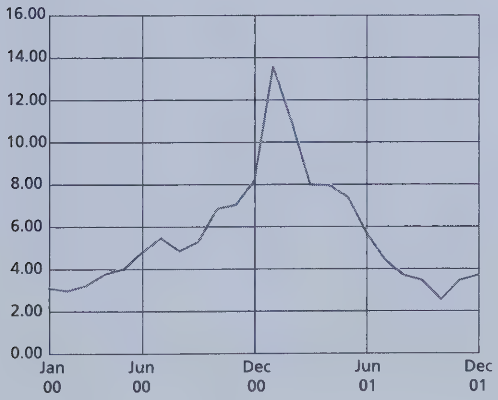
MARKETING ARRANGEMENTS

Natural Gas

Enerplus' production is currently 56% weighted towards natural gas production. The price of natural gas is dependent on North American supply and demand fundamentals. The current economic slowdown and warm winter have dramatically reduced the demand for natural gas, causing inventory storage levels to increase, resulting in downward pressure on prices. Natural gas prices are expected to remain weak for the first part of 2002, or until such time as economic and weather-related demand can demonstrate a sufficient draw on North American storage levels. The industry has reacted to lower prices with reduced drilling and capital constraints, which, combined with natural reservoir declines and the lack of exploration success, signals a longer term reduction in supply and a potential price recovery. Forecasters acknowledge the cyclical nature of the gas markets, but are uncertain how long it will take before prices recover.

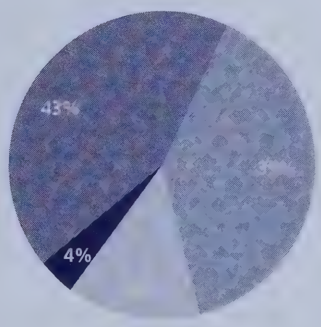
Both of the key North American natural gas price indices saw significant year over year decreases in 2001. Despite opening 2001 with a January AECO settlement price of $13.62/Mcf, natural gas prices fell consistently throughout the year reaching a low of $2.64/Mcf in October. With a fourth quarter average price of $3.30/Mcf, the 2001 annual AECO Monthly Index Price still managed to average $6.30/Mcf, up 25% from the $5.02/Mcf average for 2000. The NYMEX Henry Hub monthly reference price also declined throughout the year but nevertheless also achieved an 11% increase over 2000 levels to average US$4.38/Mcf for 2001. Enerplus' overall natural gas netback price on a combined basis at the plantgate was $5.22/Mcf, a 13% increase over the $4.60/Mcf received for 2000. As the Fund's natural gas portfolio is sold through a combination of physical and financial sales arrangements, the realized price did not increase at the same rate as the reference indices.

AECO 30 Day Spot Price (CDN$)
($/Mcf)



Natural Gas Marketing (Mcf/day)

Term Fixed Price
Spot
Aggregator Netback Pools
Term Downstream Contracts



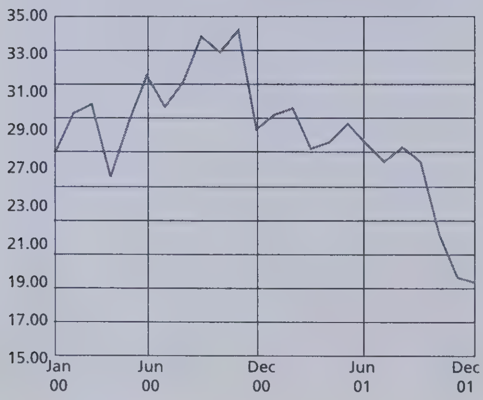
Forty three percent of the Fund's natural gas production is directly marketed in western Canada on the spot markets. An additional 14% of the portfolio, referenced as "downstream contracts", is delivered directly into the U.S. export market and is priced against the NYMEX index, net of transportation charges. A large portion of Enerplus' production is dedicated to netback price pools managed by the

major aggregators; PanAlberta Gas Ltd., Progas Limited, and the Mirant Netback Pool (formerly TransCanada Pipelines Limited). As aggregator prices continue to be lower than the prevailing indices, Enerplus is supporting industry efforts to wind-up these aggregator arrangements.

Crude Oil

The price of crude oil fluctuates with worldwide supply and demand fundamentals. For much of 2001, the OPEC countries were successful in managing oil prices within their publicly stated price band of US$24-$30 per barrel West Texas Intermediate (WTI) equivalent. However, supply management has become more difficult in recent months due to weak economic demand and the prospect that non-OPEC nations, such as Russia, are poised to attract a larger share of the world markets. The main threat to crude oil markets is a battle for market share between OPEC and non-OPEC nations. On the other hand, there are a number of factors that can put upward pressure on oil prices, including continued political instability in the Middle East, natural reservoir declines, the lack of exploration success, and an increase in demand associated with worldwide economic recovery.

WTI Crude Oil Price (US$)



The 2001 average WTI was US$25.97/bbl, down 14% from 2000. WTI crude oil prices declined from almost US$30/bbl in January to below US$20/bbl by the end of 2001, nearly 33% in one year. The Fund's netback price on a combined basis for crude oil production averaged $31.09/bbl, down a corresponding 16% from the $37.08/bbl received for 2000. Enerplus sells all of its crude oil at the lease site to marketers and refiners on 30 day evergreen contracts that fluctuate with monthly spot prices. With the majority of Canada's crude oil being exported and priced in the U.S. against the WTI US$/bbl benchmark index, Enerplus benefited from the increased weakness in the Canadian dollar. However, 12% of Enerplus' production is comprised of heavy oil (Hardisty) which is priced at a variable discount or differential to WTI.

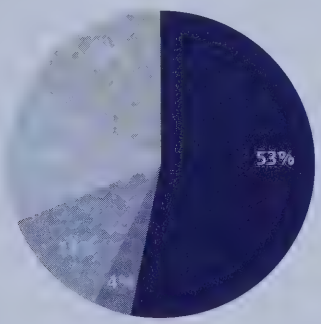
During the high price environment, the heavy oil differential increased from US$8.00/bbl in 2000 to US$10.66/bbl in 2001. Oil refiners with heavy oil refining capability were operating at near capacities as the heavy oil differentials were wide and provided opportunities for attractive refining margins. With the current decline in the underlying WTI price , heavy oil differentials today have decreased from the US$10 – US$12 range to the US$8 – US$9 range.

NGLs

Condensate and natural gas liquids production represents approximately 16% of the Fund's total production and is priced by individual product components which are primarily sensitive to weather-related demand.

Crude Oil and NGLs (bbls/day)

- Light Sweet/Light Sour
- Medium
- Hardisty Medium
- Hardisty Heavy
- Condensate & NGLs



COMMODITY PRICE RISK MANAGEMENT

Enerplus has an ongoing commodity price risk management program that is designed to provide downside price protection at a reasonable cost on a portion of its future production in the event of adverse commodity price movements, while retaining significant exposure to upside price movements. Early in 2001 while both oil and gas prices were significantly higher than historic levels, Enerplus put in place a Revenue Protection Plan by establishing floor price (put) protection on a combined volume of natural gas and crude oil which realized net gains of $50 million. The cost of the plan was approximately $0.22 per Unit and it protected approximately 36,000 BOE/day of Enerplus' combined production for the second, third and fourth quarters of 2001. While the combined prices of the second quarter were high enough that the protection was not needed, natural gas prices for the third quarter fell below the established threshold and by the fourth quarter both natural gas and crude oil prices had decreased to a level that caused the plan to realize value for the Fund and its Unitholders. The changing price environment over the past year limited the ability to enter into a similar instrument for subsequent years. However, beginning in the fourth quarter of 2001, Enerplus entered into various price protection instruments for both crude oil and natural gas which also retain significant upside price exposure.

Enerplus intends to actively manage its exposure to future commodity price fluctuations in a similar manner with the objective of providing low cost price protection against downward price movements while maintaining participation in improving price movements.

ENVIRONMENT AND SAFETY MANAGEMENT PROGRAM

Enerplus continues to develop, maintain, and continuously improve reasonable and effective environment and safety programs to ensure the protection and safety of its employees, stakeholders, and the environment. Enerplus takes very seriously its commitment to environmental and safety management and seeks to undertake its activities and operations to meet this commitment.

In 2001, Enerplus participated in a third party audit of its Environmental Management Program and is pleased to report that the required elements of an effective Environmental Management System are in place. Enerplus has integrated the management of environmental, health and safety issues into overall operating procedures to facilitate the conduct of its program. Enerplus has taken a proactive approach to the prevention of environmental incidents and mitigate impacts.

In addition, Enerplus conducted an internal audit of its Safety Management Program and is pleased to report that the components of the program continue to meet the requirements of a Certificate of Recognition (COR), which was awarded to Enerplus in 2000 through the Partnerships in Health and Safety program. The COR certifies that Enerplus' safety program meets or exceeds the requirements for a basic safety program as set out by industry and Alberta Workplace Health and Safety. It is the commitment of all management, office and field staff that ensures the continued health and safety of Enerplus' employees and stakeholders.

Employee Training

Enerplus' Job Performance Management System (JPMS) is a comprehensive approach to planning the development and progression of field operations' personnel as well as for managing risk in Enerplus' field operations. In addition to identifying and addressing hazardous tasks, JPMS is used to manage an employee's/contractor's progress and competence, to ensure that tasks are carried out safely, responsibly, and effectively. In addition, Enerplus has developed and continues to promote the Loss Control Council (LCC) in order to expand the level of on-the-job training available to its field employees. The LCC is a team of experienced and knowledgeable company employees comprising of both field and office staff from field operations, Environment and Safety, and Facilities. This team conducts inspections of operated properties each year, allowing for cross training between disciplines and sharing of information between operating areas.

Site Inspections Program

As part of its due diligence program, Enerplus conducts a number of both internal (LCC) and third party site inspections at selected operated and non-operated facilities each year. In addition, in 2001 Enerplus implemented an inspection program for construction and drilling projects. In this way the Fund ensures that its own operations as well as the operations of its partners in industry meet regulatory and industry requirements for environment and safety issues. In 2001 inspections were conducted on 16 operated areas, 5 non-operated areas, 10 construction projects, and two drilling projects, with all findings immediately addressed. All area inspections are conducted on a maximum 5 year rotation.

Corrosion Risk Management Program

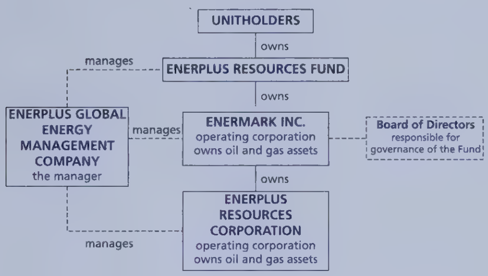
Enerplus has implemented a Corrosion Risk Management Program to address corrosion issues on pipelines and other equipment throughout its operations. The program enables Enerplus to review all pipelines operated by the Fund to assess risk of failure and to mitigate potential environmental damage that could result from corrosion related incidents. The program has assessed over twenty operated areas to date.

Acquisition Due Diligence Investigations

An integral part of property or corporate acquisitions requires that an acquisition investigation, site inspection and file review is conducted to identify significant environmental or safety issues. Potential contamination/operational issues can be identified at this stage protecting the Fund from purchasing properties with significant liabilities. In 2001, several acquisition investigations were conducted and no material environmental or safety related liabilities were noted for properties acquired.

CORPORATE GOVERNANCE PRACTICES

The corporate governance structure of Enerplus Resources Fund (the "Fund") is not the same as for a conventional corporation. The way in which the Fund is governed reflects its status as a trust. The Board of Directors (the "Board") of EnerMark Inc. ("EnerMark"), a wholly-owned subsidiary of the Fund, is responsible for the overall governance of the Fund.



The Board is currently comprised of nine members, six of whom are unrelated (as defined in the Toronto Stock Exchange Guidelines for Improved Corporate Governance in Canada) and elected by the Fund's Unitholders. The remaining three directors are nominated by the Manager pursuant to a Governance Agreement regarding the Fund and its subsidiaries. Because the Chairman of the Board is unrelated to management, he fulfills the description of "independent board leader" as set out in the recommendations of the Joint Committee on Corporate Governance, which issued a report on corporate governance in Canada in November 2001. The Board endeavours to ensure that its composition includes as many as possible of the following competencies: governance, strategic management, leadership, risk management, oil and gas, engineering, succession planning, financial management, legal, and communications and marketing expertise.

The Board has responsibility for stewardship of Enerplus, including responsibilities for planning and evaluation, financial management, operations, human resources and environment and safety. As part of its mandate, the Board has specific responsibility for:

- adopting a strategic planning process
- identifying principal risks and implementing risk management systems
- succession planning, including nominating, training and monitoring senior management
- developing a communications policy
- ensuring the integrity of internal control and management information systems

The Board meets a minimum of six times per year and each scheduled board meeting is followed by a meeting of the independent directors without the presence of management.

The Board has timely access to the information it needs to carry out its duties. Directors assist in preparing the agenda for Board and committee meetings, receive a comprehensive package of information prior to each Board and committee meeting, and attend an annual strategic planning session each fall to review, amend or adopt new corporate objectives.

The Board has approved a Code of Business Conduct and Conflict of Interest which sets high standards for ethical behaviour, and deals with conflict of interest, compliance with laws, outside business interests, entertainment, gifts and favours, disclosure, confidential information, securities trading and reporting. Each director must adhere to the standards described in the Code and must review, sign and deliver to the Chairman of the Board a copy of this Code each year.

The Fund is committed to timeliness and continuous disclosure in its communications. The investor relations

department is responsible for responding to inquiries from Unitholders, (potential or existing). Senior Management meets regularly with financial analysts and institutional investors in Canada and the United States. Presentations to institutions and at investors conferences are promptly made available on the investor relations website at **www.enerplus.com**. As well, any major developments may be broadcasted through a live conference call and made available on the Internet or via telephone.

The Board of Directors discharges its responsibilities either acting in its entirety, or through one of the following board committees:

Corporate Governance Committee

The Corporate Governance Committee is currently comprised of three unrelated directors. The Committee is responsible for the governance of the Board, including the responsibility of reviewing the mandates of the Board's committees, recommending changes to the size and composition of the Board and its committees and generally implementing good corporate governance practices. It oversees the effectiveness of management and management's interaction with and responsiveness to the Board, and reviews succession planning with subsequent approval of the full Board. The Committee assumes the responsibilities of a Nominating Committee and proposes to the full Board new nominees, assesses the performance of the directors and the Chief Executive Officer on an annual basis, and reports the results to the full Board. A corporate governance manual is available for new and existing directors. New directors meet with the Chairman of the Board and senior management to discuss and familiarize themselves with the business and activities of Enerplus. An overview of the manual, with a focus on the Enerplus corporate governance system, including, roles, responsibilities and liabilities of directors is provided on an ongoing basis. Annual environment and safety field trips are organized for all directors to allow them to review the conduct of field operations first hand. The Committee also conducts an annual survey to ensure that directors' compensation is consistent with industry standards.

Audit and Risk Management Committee

The Audit and Risk Management Committee is currently comprised of three unrelated directors. The Committee has two primary sets of responsibilities. Audit responsibilities include reviewing and recommending to the Board the approval of the annual and interim financial statements, and the engagement and audit plans of the Fund's auditors; communicating directly with the Fund's auditors and reviewing programs and policies regarding the effectiveness of internal controls over the Fund's accounting and financial reporting systems. Risk management responsibilities include reviewing, on a quarterly basis, the hedging and derivatives policies as well as the transactions entered into by the internal risk management committee and reviewing insurance coverage and directors' and officers' liability insurance, all of which are a direct responsibility of the full Board. The Audit and Risk Management Committee meets a minimum of four times per year, and meets with the external auditors, independently of management, at least twice during the financial year. Because the Fund is listed on the New York Stock Exchange, the Committee follows the Blue Ribbon Committee recommendations set out by the National Association of Securities Dealers of America and the New York Stock Exchange, including the qualification of the Committee members and their financial literacy and the requirement to adopt a formal charter. Once a year, the Chairman of the Committee will present a written statement to the full Board, certifying that the members of the Committee are financially literate

and that the Committee has reviewed its charter and determined that it meets the needs of the Board and the Unitholders of the Fund.

Compensation and Human Resources Committee

The Compensation and Human Resources Committee is comprised of two unrelated directors and one related director. The Board believes that the related director's industry knowledge and familiarity with the organization and its personnel, benefits the review and decision processes of the Committee. As well, the Board believes that because the other two members, including the Chairman of the Committee, are unrelated, the independence of the Committee is not compromised. The Compensation and Human Resources Committee is responsible for the employment, remuneration, rights incentive plan, employee savings plan and performance incentive plan. It also reviews existing management resources in terms of staffing and succession planning.

Environment, Safety and Reserves Committee

The Environment, Safety and Reserves Committee is comprised of two unrelated directors and one related director. The Board believes that the industry knowledge of the related director benefits the review and decision processes of the Committee. It also believes that, as the other two members, including the Chairman of the Committee, are unrelated, the independence of the Committee is not compromised. The Environment, Safety and Reserves Committee reviews and approves Enerplus' approach to environmental and safety regulations as well as Enerplus' Environment and Safety Management Program which encompasses internal environmental and safety policies, procedures, emergency response plans, and training. Twice yearly, Senior Management will present to the full Board a signed Corporate Environmental Due Diligence Statement, stating that after due inquiry with the appropriate staff members, Enerplus is not aware of any significant environmental issues that have not been reported to the Committee and that appropriate procedures are in place to address any such issues, should they arise. It also reviews reserves estimates prepared by the independent evaluator and in-house staff, estimated future net revenues, future development costs and timing, remaining tax pools and price and cost estimates used. Once a year, Senior Management will present a signed Corporate Statement of Compliance, stating that after due inquiry with the appropriate staff members and the independent evaluator, Enerplus is not aware of any significant reserves evaluation issues that have not been reported to the Committee and that appropriate procedures are in place to address such issues, should they arise.

Enerplus believes its approach to corporate governance is in compliance with the Toronto Stock Exchange Guidelines for Improved Corporate Governance in Canada. In addition, the Fund is currently reviewing its compliance with the recommendations contained in the final report of the Joint Committee on Corporate Governance published November 2001. A more detailed discussion of Enerplus' compliance in relation to these documents can be found in the Fund's Information Circular and Proxy Statement for its 2002 annual general and special meeting of Unitholders.

COMMUNITY INVOLVEMENT

Enerplus is committed to supporting Calgary and communities throughout western Canada where our employees live and work. The Fund provides support through contributions to specific charities and fund-raising campaigns, to local organizations and providing time for employee volunteer activities. The Fund has established guidelines for its corporate donations that support research/health/wellness, the environment, education, volunteerism, and community involvement.

Each year in support of the United Way, Enerplus stages a major internal campaign consisting of a variety of events designed to build awareness and raise money for the United Way. The campaign is planned and run by a committee comprised of representatives from staff, management and senior management. Employee donations are matched by both Enerplus Resources Fund and Enerplus Global Energy Management Company. With 89% of employees participating, Enerplus raised more than $290,000 in 2001, continuing a pattern of year-over-year growth in donating.

In 2002, Enerplus established a scholarship at the Southern Alberta Institute of Technology (SAIT) for students pursuing courses of study related to the oil and gas industry, such as geology, geophysics, land, or engineering. The scholarship is awarded based upon academic merit and the need for financial assistance.

Recently, Enerplus has committed $100,000 over the next five years toward the building of the new Alberta Children's Hospital in Calgary. This donation is a partnership between Enerplus Resources Fund and Enerplus Global Energy Management Company. The Alberta Ecotrust, a non-governmental fund-raising agency dedicated to supporting grass roots environmental projects throughout the province, has also been selected to receive support from the Fund.

Enerplus has been a supporter of the Cathedral of St. Mary's. Through the church's program, over 800 people are provided dinner every Sunday evening. Enerplus not only provides funding to cover the costs of one dinner each year, but Enerplus employees also volunteer to help with preparation, serving, and cleanup.

The Fund has instituted an innovative way to demonstrate its commitment to the community. To support employee involvement, Enerplus established the Days of Caring program wherein employees are given time off with pay to volunteer for causes which, in 2001, included the Calgary Inter-faith Food Bank, Calgary Women's Emergency Shelter, Meals On Wheels, Calgary Drop-In Center and Mustard Seed.

Through the generous support of a number of our business partners, Enerplus was able to direct additional dollars in 2001 to the Alberta Heart and Stroke Foundation, the Alberta Cancer Society, the Multiple Sclerosis Society, the Alberta Children's Hospital, and the Colin Glassco Charitable Foundation for Children.

Enerplus is proud of its tradition of community involvement and its employees' support of this tradition.

• Enerplus Unitholders received record cash distributions in 2001

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis of financial results is to be read in conjunction with the audited consolidated financial statements as at, and for the years ended December 31, 2001 and 2000, and is based on information available to March 1, 2002. All amounts are stated in Canadian dollars unless otherwise specified.

2001 HIGHLIGHTS

- On June 21, 2001, the Unitholders of Enerplus Resources Fund and EnerMark Income Fund agreed to combine the two funds and continue as Enerplus Resources Fund. This created North America's largest and most liquid conventional oil and natural gas income fund with an enterprise value of approximately $2 billion.

- In connection with the combination of the two funds, Enerplus restructured its management fee to better align the interests of the Manager and the Unitholders by eliminating acquisition and divestment fees and replacing them with performance incentive fees.
- Aside from the reverse takeover combination of Enerplus and EnerMark, acquisitions net of dispositions of producing oil and gas properties totaled $8.9 million during the year ($77.4 million in acquisitions less $68.5 million in dispositions of non-core properties). The Fund avoided high cost acquisitions in a high priced environment for much of 2001 as a result of its disciplined bidding strategy.
- Enerplus invested $143 million in development projects in 2001, drilling a record 350 net wells.
- Enerplus' commodity price risk management program generated a net gain of $50.1 million for the year, demonstrating the value of such a program during periods of price volatility.
- On November 15, 2001, the Fund issued 4,312,500 Trust Units at $24.75 per unit in a successful Canadian equity issue.

COMBINATION OF ENERMARK AND ENERPLUS

On June 21, 2001, the respective Unitholders of the EnerMark Income Fund ("EnerMark") and the Enerplus Resources Fund ("Enerplus") overwhelmingly approved a merger combining the two funds. As the former Unitholders of EnerMark held approximately 69% of the outstanding Trust Units of the combined Fund at the date of acquisition, the merger has been accounted for using the reverse takeover method of accounting for business combinations. For accounting purposes, EnerMark acquired Enerplus effective June 21, 2001 and continues as Enerplus Resources Fund which has a 16 year history, market recognition and a listing on the New York Stock Exchange.

IMPORTANT INFORMATION REGARDING COMPARATIVE FINANCIAL STATEMENTS

With the reverse takeover method of accounting, the audited consolidated financial statements presented herein include the accounts of EnerMark as at, and for the twelve months ended December 31, 2001, plus the results of Enerplus for the 193-day period from June 21, 2001 to December 31, 2001. In addition, the historical comparative financial information for the year 2000 presented in the audited consolidated financial statements is solely that of EnerMark.

In other words, the financial statements do not reflect the pre-acquisition Enerplus results for the period from January 1, 2001 to June 20, 2001, nor do they include the pre-acquisition results of Enerplus for the year ending December 31, 2000.

The remaining discussion and analysis refers to Enerplus as the combined Fund, and information included herein has been restated, as applicable, to reflect the Trust Unit exchange ratio of 1.000 EnerMark Unit for 0.173 Enerplus Unit, pursuant to the reverse takeover.

Comparison of 2001 results with those of 2000 is also complicated by the fact that EnerMark, as predecessor to Enerplus, completed five major acquisitions during 2000. Accordingly, the 2001 financial results include a full year of operations for these acquisitions, while the 2000 results reflect only a partial-year impact, commencing on the closing date of each acquisition as set forth below:

Corporate and Property Acquisitions	($ millions)	Closing Date
Enerplus Resources Fund	$ 601	Jun. 21, 2001
Cabre Exploration Ltd. (purchase of remaining 11.35% interest)	32	Jan. 8, 2001
Cabre Exploration Ltd. (purchase of 88.65% interest)	260	Dec. 31, 2000
EBOC Energy Ltd.	148	Sep. 1, 2000
Pursuit Resources Corp.	82	Apr. 3, 2000
Hanna/Garden Plains	35	Feb. 28, 2000
Western Star Exploration Ltd.	22	Jan. 7, 2000

RESULTS OF OPERATIONS

Production

As a result of changing practices in the oil and gas industry in Canada, Enerplus has adopted the standard of 6 Mcf:1 barrel of oil equivalent when converting natural gas to barrels of oil equivalent ("BOE"). In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise indicated.

Daily production averaged 54,015 BOE per day during 2001, representing a 74% increase over production volumes of 31,112 BOE per day the previous year. The increase is attributed to the reverse takeover of Enerplus by EnerMark on June 21, 2001, as well as the previously mentioned acquisitions during 2000. The acquisitions in 2000 had a full year impact on 2001 production, but only a partial-year impact on 2000 production, relative to the respective closing date of the acquisition.

Enerplus' production is widely distributed across more than 250 properties in Alberta, Saskatchewan and British Columbia. The largest 10 properties account for 31% of Enerplus' production. This wide distribution minimizes the risk that production might be materially impacted by the performance of a few major properties.

Average production volumes for the years ended December 31, 2001 and 2000 are outlined below:

Daily Production Volumes	2001[1]	2000	% Change
Natural gas (Mcf/day)	176,671	101,473	74%
Crude oil (bbls/day)	20,592	12,089	70%
Natural gas liquids (bbls/day)	3,978	2,111	88%
Total daily sales (BOE/day)	54,015	31,112	74%

[1] 2001 production reflects only 193 days of the post-merger Enerplus production (from June 21, 2001 to December 31, 2001) after the date of the reverse takeover.

Enerplus' exit production rate averaged 62,300 BOE per day for the month of December 2001, with a weighting of 56% natural gas, 37% crude oil, and 7% natural gas liquids. Production is currently expected to average 61,000 BOE per day in 2002, after considering a full-year impact from the reverse takeover of Enerplus and a forecast $130 million in development capital spending, but without taking into account any further acquisitions.

PRICING AND PRICE RISK MANAGEMENT

The average price that Enerplus received for its natural gas (before hedging) increased 9% from $4.52/Mcf in 2000 to $4.91/Mcf in 2001. In comparison, the AECO monthly index increased 25% from $5.02/Mcf in 2000 to $6.30/Mcf in 2001 and the NYMEX index price increased 12% from $3.91/Mcf in 2000 to $4.38/Mcf in 2001. Enerplus' realized gas prices did not increase as much as the reference indices due to:

- Long-term fixed price physical delivery contracts representing approximately 5% of production that were priced below prevailing index prices in 2001; and
- Sales to aggregators that were also priced below prevailing indices in 2001 because they reflect a basket of fixed, floating, and downstream delivery contracts.

The average price that Enerplus received for its crude oil (before hedging) decreased 15% from CDN$35.86/bbl in 2000 to CDN$30.48/bbl in 2001. This reflects a comparable 14% decline in the pricing of benchmark West Texas Intermediate (WTI) crude oil. Enerplus benefited from the weaker Canadian exchange rate and a lighter average blend of crude oil as a result of recent acquisitions, however, these advantages were offset by wider price differentials on heavier streams of crude oil during the year.

The realized prices for natural gas liquids ("NGLs") decreased 4% from the previous year to average $31.12/bbl in 2001. However, the price of NGLs as a proportion of Enerplus' crude oil price increased from 90% in 2000 to 102% in 2001 reflecting significantly higher values attributed to ethane production in the first half of 2001.

Average Selling Price (CDN$) Before the Effects of Hedging	2001	2000	% Change
Natural gas (per Mcf)	$ 4.91	$ 4.52	9%
Crude oil (per bbl)	30.48	35.86	(15)%
Natural gas liquids (per bbl)	31.12	32.33	(4)%
Total daily sales (per BOE)	$ 29.89	$ 30.94	(3)%

Benchmark Pricing	2001	2000	% Change
AECO natural gas (per Mcf)	$ 6.30	$ 5.02	25%
NYMEX natural gas (US$ per Mcf)	4.38	3.91	12%
WTI crude oil (US$ per bbl)	25.97	30.19	(14)%
CDN$/US$ exchange rate	$ 0.6458	$ 0.6736	(4)%

Enerplus has an on-going commodity price risk management program that is designed to provide price protection on a portion of its future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. The program is intended to provide a measure of stability to the Fund's cash distributions as well as ensure Enerplus realizes positive economic returns from its capital development and acquisition activities.

In 2001, Enerplus realized a gain of $50.1 million as a result of its price risk management program, as outlined below:

Opportunity Gain (Loss) from Financial Hedging ($millions)	2001	2000
Crude oil	$ 5.5	$ (9.6)
Natural gas	44.6	0.5
Net hedging opportunity gain (loss)	$ 50.1	$ (9.1)
Net gain (loss) per bbl crude oil	$ 0.73	$(2.19)
Net gain (loss) per Mcf natural gas	$ 0.69	$ 0.01

Enerplus' commodity risk management position as at December 31, 2001 is described in Note 8 to the financial statements. Commodity price risk is managed through fixed price physical delivery contracts and financial instruments such as forward contracts. The net receipts or payments arising from the forward contracts are recognized in income as a component of oil and gas sales during the same period as the corresponding hedge position. At December 31, 2001, Enerplus had $4.6 million in deferred costs related to forward contracts that will be amortized over the remaining life of those instruments. The mark-to-market value of the financial forward contracts represented an unrealized loss of $0.4 million with reference to year-end prices and forward markets.

Subsequent to year end, on January 8, 2002, Enerplus entered into an additional 3-way financial option on 1,500 bbls/day of oil from April 2002 to December 2003. Under the terms of this option Enerplus purchased a WTI put at US$19.50/bbl, sold a WTI call at US$27.00/bbl and sold a WTI put at US$17.00/bbl. Enerplus also entered into a 3-way option on 9,480 Mcf/day of natural gas for the period from April to October 2002, selling an AECO call at $4.22/Mcf, purchasing an AECO put at $3.29/Mcf and selling an AECO put at $2.37/Mcf. The cost of this gas price protection was mitigated by selling an AECO call at $6.33/Mcf for the period from November 2002 to March 2003.

In the future, Enerplus intends to continue to manage its commodity price exposure in a similar manner with the objective of establishing downside price protection at a reasonable cost, while maintaining exposure to improving prices. The future gain or loss from such a program depends on forward markets and future prices. Readers are cautioned that the significant hedging gains experienced in 2001 are not expected to be replicated in 2002.

REVENUES

Crude oil and natural gas revenues, including hedging gains, were $639.4 million for the year ended December 31, 2001, which was 86% higher than the $343.2 million reported for the year ended December 31, 2000. This substantial increase was due to the reverse takeover of Enerplus on June 21, 2001, as well as the acquisitions of Cabre, EBOC, Pursuit, and Western Star and the acquisition of the Hanna/Garden Plains property during 2000. The acquisitions in 2000 had a full year impact on 2001 revenues, but only a partial-year impact on 2000 revenues, depending on the closing date of the acquisition. Enerplus' 2001 increase in revenues was primarily the result of lighter production volumes and hedging gains offset by a slight reduction in prices as described in the table below.

Analysis of Sales Revenues ($millions)	Crude Oil Revenues	NGL Revenues	Natural Gas Revenues	Total Revenues
2000 Sales Revenues	$149.0	$25.0	$169.2	$343.2
Price variance	(40.4)	(1.8)	25.1	(17.1)
Volume variance	110.8	22.0	121.3	254.1
Hedging gain variance	15.1	-	44.1	59.2
2001 Sales Revenues	**$234.5**	**$45.2**	**$359.7**	**$639.4**

ROYALTIES

Royalties increased by $51.7 million to $132.7 million for the year ended December 31, 2001, as a consequence of the increase in production revenue. The royalty rate before hedging for the year ended December 31, 2001, decreased to 22.5% from 23.0% for the year 2000. In the current commodity price environment, Enerplus expects a royalty rate of approximately 21% for 2002, without taking into account future acquisitions.

OPERATING EXPENSES

Operating expenses increased to $120.1 million for the year ended December 31, 2001 from $55.0 million in 2000, due mainly to the higher production volumes associated with acquisition activities. This represents a cost of $6.09/BOE in 2001 compared to $4.83/BOE in 2000. Increased activity levels in the industry during the first nine months of 2001 created a higher demand for goods and services and placed a corresponding upward pressure on costs. In addition, Enerplus experienced higher electricity costs in the first half of 2001 compared to 2000. Finally, the acquisition of properties during 2000 and 2001 with relatively higher operating costs than the pre-existing property portfolio added to Enerplus' operating cost per BOE.

Lower electricity costs and reduced activity levels in the industry are expected to stabilize and moderate Enerplus' operating expenses in 2002.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses were $13.0 million for the year ended December 31, 2001 compared to $7.2 million for the year 2000. The increase reflects the additional costs of managing entities acquired during 2000 for a full year. General and administrative costs per BOE of production increased marginally to $0.66/BOE for 2001 compared to $0.63/BOE for 2000.

In accordance with the full cost method of accounting, Enerplus capitalized $7.5 million of G&A costs in 2001 compared to $7.9 million capitalized in 2000. The majority of these capitalized costs represent compensation costs for staff involved in development drilling and acquisition activities.

In 2002 the Fund is targeting G&A costs of approximately $0.60/BOE, before taking into account any further acquisitions.

MANAGEMENT FEES

Management services are supplied to Enerplus on a fee and cost reimbursement basis. Management fees expensed were $9.3 million for the year ended December 31, 2001 represents an increase of $4.8 million over the year 2000 as a result of higher operating income as well as the increase in the base management fee percentage as discussed below relative to the restructuring of management fees in their entirety.

In conjunction with the reverse takeover of Enerplus, a new management agreement was approved by the Unitholders on June 21, 2001. Under the new agreement, base management fees were set at 2.75% of operating income (compared to pre-June 21, 2001 rates of 2.2% for EnerMark and 3.5% for Enerplus). In addition, acquisition and divestment fees (capitalized for financial statement purposes) were eliminated and were replaced by performance fees based on both the total return of the Fund, and its relative performance as compared to other senior conventional oil and gas trusts. The performance fee can range between 0% and 4% of operating income. In connection with the merger, the management company was paid a fee of 172,500 Enerplus Trust Units with a value of $5 million in 2001, which was capitalized as part of the merger cost. The management fee is described in Note 6 to the financial statements.

In 2002, the base management fee will be 2.75% of the Fund's operating income. In addition, there are two types of incremental performance fees which can range in aggregate from 0% to 4%:

Total Return Performance Fee (minimum 0%, maximum 2% of the Fund's operating income)

1. If the total return of Enerplus Units (amount of distributions and appreciation in Trust Unit price) exceeds 11%, then the Total Return Performance Fee will be a minimum of 0.5%.
2. If the total return of Enerplus Units is less than the yield on 10-year Government of Canada bonds plus 5%; then the Total Return Performance Fee will be 0% (subject to the minimum payment described in (1) above).
3. If the total return of Enerplus Units exceeds the yield on 10-year Government of Canada bonds plus 15%; then the Total Return Performance Fee will be 2% of the operating income of the Fund.
4. If the total return of Enerplus Units is between the yield on 10-year Government of Canada bonds plus a factor of 5% to 15% (subject to the minimum payment described in (1) above), then a sliding scale calculation (ranging from 0% to 2%) will be used.

Relative Performance Fee (minimum 0%, maximum 2% of the Fund's operating income)

1. The relative performance of Enerplus as compared to seven other qualifying conventional oil and gas trusts will be ranked based on distributions and unit price appreciation.

2. The Relative Performance Fee will be calculated using a percentage equal to 2% divided by the number of trusts in the top half of the rankings multiplied by the number of rankings which Enerplus is below the number one ranking and subtracting the product obtained thereby from 2%; and

3. If the resulting value obtained is less than zero, then no Relative Performance Fee will be paid, otherwise the Relative Performance Fee will be the amount obtained by multiplying the resulting percentage (not to exceed 2%) by the operating income of the Fund.

In effect, Enerplus must rank at least fourth out of the eight largest conventional oil and gas trusts (including Enerplus) before any Relative Performance Fee is payable.

This fee arrangement will be reviewed annually with the Board of Directors. The new management fee arrangements were designed to better align the interests of the Manager with the interests of Unitholders.

INTEREST EXPENSE

Interest expense for the year 2001 was $17.6 million, up $2.3 million from 2000 due to higher outstanding bank debt incurred in connection with the acquisition activities in 2000 and 2001. Bank debt increased to $412.6 million at December 31, 2001 from $275.9 million on December 31, 2000.

During 2001, Enerplus' interest costs were entirely based on floating rates, as those rates offered the most cost-effective financing strategy. Subsequent to the year end, Enerplus entered into an interest rate swap that fixed the rate on a notional $25 million in debt for a three year term from January 18, 2002 to January 18, 2005 at a rate of 3.89% per annum (before banking fees that are expected to range between 0.85% and 1.05%). Enerplus may consider fixing an additional portion of its interest rate exposure in 2002, depending on its financing requirements and the forward interest rate market.

DEPLETION AND CEILING TEST

Depletion of the property, plant and equipment is provided on the unit-of-production method based on constant price proven reserves. An estimate of the future costs for restoration and abandonment of well sites and facilities is updated annually and this cost estimate is amortized over the life of the properties on a unit-of-production basis.

	2001	2000
Depletion and depreciation	$ 181.1	$ 76.5
Amortization of future site restoration	5.9	3.8
Amortization of deferred hedging costs	7.1	-
Total	$ 194.1	$ 80.3

Depletion, depreciation and amortization increased to $194.1 million in 2001 from $80.3 million in 2000. Included in the amortization amount are $7.1 million of amortized costs relating to the mark-to-market value of the Enerplus commodity price forward contracts at the time of the reverse takeover. The mark-to-market value of these contracts was recognized as either a deferred hedge asset or liability as part of the acquisition cost and will be amortized over

the remaining term of the contract ending in 2004. The actual gain (or loss) associated with this contract will be recognized in oil and gas sales as they are realized.

The rate of depletion and depreciation has increased to $9.18/BOE in 2001 from $6.72/BOE in 2000. The increase is the result of higher costs attributed to petroleum and natural gas assets acquired during 2000 and 2001. The adoption of the liability method of accounting for future income taxes, as required by Canadian generally accepted accounting principles, had the effect of substantially increasing the recorded value of acquired property, plant and equipment compared to the previous deferral method of accounting. In the case of the corporate acquisitions in 2000 the value of acquired assets were increased to reflect any shortfall between the net book value and the cost basis for income tax purposes.

Enerplus places a limit on the carrying value of property, plant and equipment (the "ceiling test"). The cost of these assets, less accumulated depletion, is limited to the estimated future net revenue from proved reserves (based on unescalated prices and costs at the balance sheet date) less estimated future general and administrative costs, financing costs, and management fees. There was a surplus in the ceiling test at year end 2001.

TAXES

Capital taxes increased to $4.7 million for the year 2001 from $2.9 million in 2000 primarily due to the increase in capital structure.

For the year ended December 31, 2001, a future income tax recovery of $31.5 million was recorded in income. Under Canadian generally accepted accounting principles, the Fund does not recognize any future income taxes, as taxable income is distributed to Unitholders in the form of taxable distributions. However, the Fund's operating companies are required to account for future income taxes. Future income taxes arise because of the difference between the accounting and tax bases of the operating companies' assets and liabilities.

NETBACKS

Netbacks per BOE of Production (6:1) year ended December 31,	2001	2000
Oil and gas sales	$ 32.43	$ 30.14
Royalties	(6.73)	(7.10)
Operating expenses	(6.09)	(4.83)
General and administrative expenses	(0.66)	(0.63)
Management fees	(0.47)	(0.40)
Interest expense, net of interest and other income	(0.85)	(1.30)
Capital taxes	(0.24)	(0.26)
Restoration and abandonment cash costs	(0.13)	(0.13)
Funds flow from operations	17.26	15.49
Depletion and depreciation	(9.18)	(6.72)
Amortization, net of cash costs	(0.54)	(0.21)
Future income tax recovery (provision)	1.60	(1.35)
Net income per BOE of production	$ 9.14	$ 7.21

NET INCOME AND FUNDS FLOW FROM OPERATIONS

Net income for the year ended December 31, 2001 was $180.3 million, or $3.28 per Trust Unit, up 119% (7% per Trust Unit) from $82.2 million or $3.06 per Trust Unit for the year 2000. After adding back non-cash expenses such as depletion, depreciation, amortization and the future income tax provision (recovery), the resultant Funds Flow from Operations was $340.2 million in 2001 or $6.20 per Trust Unit compared to $176.4 million or $6.57 per Trust Unit in 2000.

QUARTERLY FINANCIAL INFORMATION

$millions, except per Unit amounts	Oil and Gas Revenue Net of Royalties	Net Income	Net Income per Unit Basic	Net Income per Unit Diluted
2001				
First quarter	$ 136.7	$ 59.7	$1.42	$1.41
Second quarter	109.3	58.5	1.30	1.29
Third quarter	130.9	25.1	0.39	0.39
Fourth quarter	129.8	37.0	0.55	0.55
Total	**$ 506.7**	**$ 180.3**	**$3.28**	**$3.28**
2000				
First quarter	$43.5	$10.1	$0.45	$0.45
Second quarter	55.4	10.9	0.42	0.42
Third quarter	68.6	23.9	0.88	0.88
Fourth quarter	94.7	37.3	1.16	1.16
Total	**$262.2**	**$82.2**	**$3.06**	**$3.05**

CASH AVAILABLE FOR DISTRIBUTION

Enerplus distributes the net cash flow from its oil and gas properties to the Trust Unitholders on a monthly basis. A portion of this cash flow is typically withheld to repay bank debt incurred with respect to acquisitions and capital spending. For the year ended December 31, 2001, Enerplus generated $340.2 million in Funds Flow from Operations. Of this amount (together with certain funds described in the following table), $316.5 million was paid to Unitholders and $48.8 million was retained for debt reduction.

Management monitors the Fund's distribution payout policy with respect to forecast cash flows, debt levels, and spending plans. The level of cash retained for debt repayment typically varies between 5% and 10% of total cash flow, although management is prepared to adjust the payout levels in an effort to balance the investor's desire for distributions with the Fund's requirement to maintain a prudent capital structure.

The following table reconciles Enerplus' "Funds Flow from Operations" as per the Statement of Cash Flows with the cash available for distribution to Unitholders.

Reconciliation of Cash Available for Distribution for the year ended December 31, $millions, except per Unit amounts	2001	2000
Funds flow from operations	$ 340.2	$ 176.4
Site restoration and abandonment costs incurred	2.6	1.4
Cash withheld for debt reduction	(48.8)	(11.7)
Enerplus cash flows (Note A)	16.9	-
Accruals (Note B)	5.6	-
Pursuit cash flows, net of debt reduction (Note C)	-	2.1
Cash available for distribution (Note D)	$ 316.5	$ 168.2
Cash available for distribution per Trust Unit	$ 5.67	$ 5.49

Cash available for distribution per Trust Unit of $5.67 for 2001 represent what an EnerMark Unitholder would have received for the 2001 production year (which was paid to Unitholders from March 20, 2001 to February 20, 2002) after converting 1 EnerMark Unit for 0.173 Enerplus Unit pursuant to the terms of the Merger. Similarly, cash available for distribution of $5.49 per Trust Unit for the 2000 production year was paid to EnerMark Unitholders between March 20, 2000 and February 20, 2001.

Note A: As a result of the reverse takeover, funds flow from operations do not include funds earned by the former Enerplus prior to June 21, 2001. However, cash distributions include the July/August payment in respect of this cash flow. As a result, the July/August payment to Unitholders is added to funds flow from operations for purposes of this reconciliation.

Note B: According to the current Royalty Agreement with Enerplus Resources Corporation, the royalty paid to the Fund must be on a cash basis. As a consequence, the change in accrued net revenues for the year are added back to funds flow from operations for purposes of this reconciliation.

Note C: In the acquisition of Pursuit Resources Corp., Enerplus distributed a portion of the Pursuit net cash flow generated between the effective date and the closing date of the acquisition.

Note D: The cash for distribution of $316.5 million in 2001 can be reconciled to the cash paid to Unitholders of $328.9 million on the Statement of Cash Flows by subtracting the January and February 2001 payments to Unitholders and adding the January and February 2002 payments to Unitholders, as the Statement of Cash Flows reflects cash payments to Unitholders during the calendar year.

CAPITAL EXPENDITURES

During the year ended December 31, 2001, Enerplus spent $152.2 million (2000 - $65.8 million) on capital expenditures and acquisitions net of divestitures.

Capital Expenditures for the year ended December 31, $millions	2001	2000
Development drilling and completions	$ 83.0	$ 27.1
Plant and facilities	53.6	11.9
Office and other expenditures	6.7	1.0
Total	143.3	40.0
Acquisitions of oil and gas properties	77.4	51.1
Dispositions of oil and gas properties	(68.5)	(25.3)
Total Net Capital Expenditures	$ 152.2	$ 65.8

Enerplus finances its capital expenditures through bank borrowing, new equity issues, and by withholding a portion of funds flow from operations. The following table outlines the development spending by major property:

Capital Expenditures for the year ($millions) ended December 31,	2001				2000
	Development Drilling	Facilities	Other	Total	Total
Hanna/Garden Plains	$ 11.5	$ 11.9	$ 1.7	$ 25.1	$ 3.5
Pembina Five Way	7.2	1.7	-	8.9	-
Medicine Hat	6.7	5.8	-	12.5	0.5
Bantry	7.7	2.3	-	10.0	1.9
Benjamin	2.4	3.2	0.1	5.7	1.4
Giltedge	0.4	3.8	-	4.2	9.7
Other	47.1	24.9	4.9	76.9	23.0
Total	$ 83.0	$ 53.6	$ 6.7	$ 143.3	$ 40.0

Enerplus is currently forecasting capital expenditures of approximately $130 million in 2002 on existing properties. Of this total, Enerplus expects to spend $20 million at Joarcam drilling 18 potential oil wells and 5 potential gas wells, recompleting 30 wells, and increasing the facility infrastructure capacity in the region. At Hanna/Garden Plains, Enerplus expects to spend $12 million drilling 75 shallow gas wells, performing well workovers and completing facility modifications. At Medicine Hat North, the capital budget of $9 million includes drilling 50 potential gas wells and installation of compression in the region. At Bantry, Enerplus expects to spend $5 million drilling 37 potential gas wells and refracing existing wells.

Enerplus routinely evaluates its property portfolio and disposes of properties that are viewed as non-core holdings with limited contribution to cash flow or upside development potential. In 2001, Enerplus sold $68.5 million worth of non-core oil and gas properties. Offsetting these dispositions were $77.4 million of acquisitions for the year, including $25.0 million on Kaybob, $8.8 million on Ferrier, and $8.3 million on Gleneath. Enerplus expects to continue its process of rationalizing marginal properties and acquiring new properties in 2002.

LIQUIDITY AND CAPITAL RESOURCES

Enerplus' bank debt increased to $412.6 million as at December 31, 2001 compared to $275.9 million at December 31, 2000.

Continuity of Bank Debt ($millions)	2001	2000
Beginning balance January 1,	$ 275.9	$ 131.3
Items that affect bank debt as per Statement of Cash Flows		
Purchase of property, plant and equipment	243.0	251.9
Proceeds on sale of property, plant and equipment	(75.3)	(18.5)
Assumption of acquired entities' bank debt	78.6	66.9
Proceeds from issue of Trust Units	(151.4)	(120.6)
Cash distributions paid to Unitholders during the calendar year	328.9	132.6
Funds flow from operating activities (on an accrued basis)	(340.2)	(176.4)
Increase in non-cash operating working capital	52.9	11.4
Other	0.2	(2.7)
Ending Bank Debt December 31,	$ 412.6	$ 275.9
Bank Debt per Trust Unit at December 31,	$ 5.93	$ 6.74

As at March 1, 2002, Enerplus renegotiated its bank facilities and consolidated the bank lines of the former EnerMark and Enerplus operating companies. Enerplus currently has $620 million committed under the unsecured bank facilities with a syndicate of 7 banks, comprised of a $590 million revolving 364 day committed facility with an incremental amortizing two-year term, and an additional $30 million demand operating facility. These credit facilities have no financial covenants, however, the size of the facility is based on the banks' evaluation of the value of Enerplus' proven oil and gas reserves. The banks have reserved the right to revise the commitment based on a review of the year end reserve information. The bank debt has priority over claims of and distributions to the Unitholders. However, Unitholders have no direct liability with respect to the bank loan should revenues be insufficient to repay it.

In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, Enerplus will be required to maintain certain minimum balances on deposit with the syndicate agent.

Financial Leverage and Coverage	2001	2000
Bank debt to funds flow from operations	1.2x	1.6x
Funds flow from operations to interest expense	19.3x	11.5x
Bank debt to bank debt plus equity	23%	27%

Enerplus has no off-balance sheet financing arrangements.

In 2002, Enerplus may consider replacing a portion of its bank debt with term debt (such as 5-10 year debentures) in order to diversify credit sources, secure term financing commitments, and potentially fix interest rates for a longer term.

NATURAL GAS PIPELINE COMMITMENTS

Enerplus has contracted to transport 10MMcf/day of natural gas into Chicago on the Foothills and Northern Border pipelines until October 31, 2008. It has also agreed to transport 5 MMcf/day to Marshfield, Illinois on the TransCanada and Viking pipelines until October 31, 2008. In addition, Enerplus has pipeline commitments to transport 5 MMcf/day into Chicago on Alliance Pipeline until October 31, 2015.

TRUST UNIT INFORMATION

Enerplus had 69,532,000 Trust Units and no warrants outstanding at December 31, 2001 compared to 40,925,000 Trust Units and 3,045,000 warrants at December 31, 2000. The weighted number of Trust Units outstanding during 2001 was 54,907,000 (2000 - 26,841,000).

During 2001, Enerplus issued 20,863,000 additional Trust Units pursuant to the Merger agreement on June 21, 2001. In addition, 1,267,000 Trust Units were issued to acquire the non-controlling interest with respect to the Cabre acquisition, and 4,312,500 Trust Units were issued pursuant to the November 15, 2001 equity offering. Enerplus also issued 3,045,000 warrants on December 31, 2000 and an additional 390,000 warrants on January 8, 2001 pursuant to the Cabre acquisition, of which 1,197,000 were exercised during 2001 and 2,238,000 expired on December 17, 2001.

INCOME TAXES

The following sets out a general discussion of the Canadian and U.S. tax consequences of holding Enerplus Trust Units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Unitholders or potential Unitholders should consult their own legal or tax advisors as to their particular tax consequences.

CANADIAN TAXPAYERS

The Fund qualifies as a mutual fund trust under the Income Tax Act (Canada) and, accordingly, Trust Units of the Fund are qualified investments for RRSPs, RRIFs, RESPs, and DPSPs. Each year, the Fund is required to file an income tax return and any taxable income in the Fund is allocated to the Unitholders.

Unitholders are required to include in computing income their pro-rata share of any taxable income earned by the Fund in that year. An investor's adjusted cost base ("ACB") in a Trust Unit equals the purchase price of the Unit less any non-taxable cash distributions received from the date of acquisition. To the extent a Unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the Unitholder and the Unitholder's ACB will be brought to $nil.

Enerplus paid $6.25 per Trust Unit in cash distributions to Unitholders during the 2001 calendar year. For Canadian tax purposes, 25% of these distributions, or $1.54 per Unit was a tax deferred return of capital, 74% or $4.6269 per Unit was taxable to Unitholders as other income, and 1% or $0.0831 per Unit was taxable dividend income.

U.S. TAXPAYERS

U.S. Unitholders who receive cash distributions are subject to a 15% Canadian withholding tax, applied to the taxable portion of the distribution as computed under Canadian tax law. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distribution for U.S. tax purposes is determined by Enerplus in relation to its current and accumulated earnings and profits using U.S. income tax principles. The taxable portion so determined is considered to be a dividend for U.S. tax purposes.

The non-taxable portion of the cash distribution, is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss arising from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as gains.

Enerplus paid US$3.83 per Trust Unit to U.S. residents during the 2001 calendar year, of which 13% or US$0.49 per Unit was a tax deferred return of capital and 87% or US$3.34 per Unit was a taxable dividend.

BUSINESS RISKS

Investors that purchase Enerplus Trust Units are participating in the net cash flow from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the cash flow paid to investors and the value of Enerplus Units are subject to numerous risk factors. These risk factors, many of which are associated with the oil and gas industry, include, but are not limited to the following influences:

- The prices that Enerplus receives for its crude oil, natural gas, and NGLs can fluctuate significantly due to global and North American supply and demand, worldwide economic conditions, weather, political stability, Canada/U.S. exchange rates, the proximity to and capacity of transportation and processing facilities, the price and availability of alternative fuels and government regulations. Declines in oil or natural gas prices will have an adverse effect on our operations, financial condition, reserves and ultimately our ability to pay distributions to Trust Unitholders.
- Oil and natural gas reserves naturally deplete as they are produced over time. Enerplus' ability to replace production depends on its success in acquiring new reserves and developing existing reserves. Since Enerplus distributes the majority of its net cash flow to Unitholders, it must finance a large portion of this acquisition and development activity through continued access to the equity and debt capital markets. As such, it is dependent on continued access to the capital markets to maintain and grow value for Unitholders.
- Acquisition of oil and gas assets depend on Enerplus' assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to Unitholders and the value of the Trust Units.
- The value of Enerplus Trust Units is based on the underlying value of the oil and gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and natural gas prices increase the risk of write-downs of Enerplus' oil and gas property investments.
- Changing interest rates can affect borrowing costs and the market price of yield-based investments such as Enerplus.

- Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on Enerplus.
- Operating costs may be difficult to control as increased activity in the oil and gas industry may increase the cost of goods and services and make it difficult to hire and retain staff.
- Third party operators operate approximately 35% of Enerplus' production, which reduces Enerplus' ability to control costs, capital, and operation activities with respect to these properties.
- Enerplus assumes customer credit risk associated with oil and gas sales, financial hedging transactions, and joint venture participants.
- Environmental and safety risks influence the workforce, operating costs, and compliance with regulatory standards.

Enerplus has no control over many of these risk factors. Nevertheless, management has attempted to mitigate some of these risks through the following:

- Enerplus has an ongoing commodity price risk management strategy that is intended to provide price protection on a portion of its future production in the event of adverse commodity price movement, while retaining exposure to upside price movements.
- Enerplus has listings on the Toronto and New York Stock exchanges and maintains an active investor relations program designed to facilitate access to equity capital markets.
- Enerplus maintains a prudent capital structure by retaining a portion of the cash flow for debt repayment, rationalizing properties that no longer meet portfolio guidelines, managing capital expenditures within rate of return guidelines, and utilizing the equity markets when appropriate.
- Acquisitions are subject to stringent investment criteria, due diligence, and review and approval by the Fund's Board of Directors. Independent reservoir engineers evaluations are required for acquisitions in excess of $5 million.
- Enerplus strives to acquire low risk, mature properties with a high proportion of proven reserves, high cash netbacks, long reserve lives, and predictable production.
- Similarly, Enerplus participates in lower-risk development projects, while farming out or monetizing higher risk exploratory prospects.
- Each year a significant portion of Enerplus' proven and probable oil and gas reserves are evaluated by a firm of independent reservoir engineers. Approximately 83% of the net present value of the total established reserves discounted at 12% were evaluated at December 31, 2001. A special committee of the Board of Directors reviews and approves the reserve report.
- Enerplus monitors the interest rate forward market and has recently begun to fix the interest rate on a portion of its debt through interest rate swaps for terms up to 3 years. In addition, the Fund may consider fixing longer-term interest rates in conjunction with the issuance of longer-term debentures.
- Management has established credit policies and controls designed to limit the risk of default or nonpayment with respect to oil and gas sales, financial hedging transactions, and joint venture participants.

- Enerplus offers competitive incentive-based compensation packages to attract and retain qualified staff.
- Enerplus has employee training and safety programs designed to educate on safety awareness, monitor incidents and prevent accidents.
- Enerplus has a site inspections program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations.
- Enerplus maintains certain insurance coverages related to liability and property exposures.

BUSINESS PROSPECTS

Enerplus strives to be the premier oil and gas income fund in North America by continuing to deliver top quartile returns to its Unitholders. The Fund's objective is to increase value for Unitholders through successful acquisitions and the low-risk development of its existing properties utilizing technology, creativity and innovation.

Enerplus offers investors the benefits of owning a diversified portfolio of mature crude oil and natural gas producing properties and related facilities. As such, the most influential factor affecting the future prospects of the Fund is the price of crude oil and natural gas. Commodity prices continue to be volatile and difficult to forecast.

Natural gas prices are expected to remain weak for the first part of 2002, or until such time as economic and weather-related demand can reduce the current North American storage oversupply. Over the longer term, Enerplus expects natural gas prices to strengthen, although not to the elevated levels experienced in the first quarter of 2001. A cyclical re-balancing of gas supply is expected as reduced exploration and development drilling, combined with natural reservoir depletion, reduces supplies at the same time North American demand is recovering.

The price of crude oil has weakened since the third quarter of 2001 due to reduced economic demand and the threat that OPEC may abandon its production quota practices in an attempt to regain market share from non-OPEC nations. Other developments, such as continued political instability in the Middle East, natural reservoir declines, reduced exploration and development drilling, and signs of a worldwide economic recovery are creating compensating upward pressure on oil prices.

Enerplus has a price risk management strategy that is designed to provide a measure of price protection in the event of adverse commodity price movement, while retaining exposure to upside price movements. At year end, approximately 28% of Enerplus' expected natural gas production and 15% of its expected crude oil production was protected against downward price movement. Even with these positions, the Fund's cash flow remains sensitive to changes in commodity prices as demonstrated by the following table:

Sensitivity to Changes in Price and Exchange Rate	Effect on 2002 Distributions per Trust Unit
Change of CDN$0.10 per Mcf in the price of natural gas	$0.07
Change of US$1.00 per barrel in the price of WTI crude oil	$0.15
Change of 1,000 BOE/day in production	$0.06
Change of $0.01 in the US$/CDN$ exchange rate	$0.04
Change of 1% in interest rate	$0.05

As with most yield-based investments, the level of interest rates can have an impact on the trading value of Enerplus Trust Units. The recent period of declining interest rates has had a positive impact on Enerplus' Trust Unit value and the Fund's ability to raise capital. While the prospect of an economic recovery may reverse the current trend of low interest rates, such a recovery would be positive for the oil and natural gas markets, and it is expected that the benefits associated with a commodity price recovery far outweighs the risk of rising short-term interest rates.

The combination of Enerplus and EnerMark has created the largest conventional oil and gas income fund in North America. It has increased liquidity for investors and attracted a broader base of institutional and U.S. investors through its listings on the TSE and NYSE. More importantly, it has improved the Fund's access to capital and its ability to pursue large acquisition opportunities.

Enerplus also has numerous internal development opportunities on existing properties, including low risk development drilling, the application of waterflood technology, and application of incremental recovery techniques designed to increase production and improve reservoir recoveries. In particular, Enerplus has a large inventory of low-cost shallow gas drilling opportunities that can be activated quickly in the event of a recovery in natural gas prices.

As Enerplus distributes much of its net cash flow, its ability to replace production and grow Unitholder value depends on its success in acquiring new reserves. Although Enerplus bid on numerous asset and corporate packages throughout 2001, the Fund was largely unsuccessful due to its disciplined acquisition criteria. With the recent decline in commodity prices, the desire or need of many E&P companies to strengthen their balance sheets, and the asset rationalization that typically follows a period of industry consolidation, we expect that 2002 will bring better opportunities to acquire quality properties at more reasonable prices.

FORWARD-LOOKING STATEMENTS

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of Enerplus. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed above, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management of the Fund is responsible for the preparation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles and for the consistency, therewith, of all other financial and operating data presented in this report.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of relevant, reliable, and timely information.

External auditors, appointed by the Fund's Unitholders, have examined the consolidated financial statements of the Fund. The Audit Committee, consisting of external directors, has reviewed these statements with management and the auditors and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Fund.

Gordon J. Kerr
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
March 1, 2002

AUDITORS' REPORT

To the Unitholders of Enerplus Resources Fund:

We have audited the consolidated balance sheet of Enerplus Resources Fund as at December 31, 2001 and the consolidated statements of income, accumulated income, accumulated cash distributions, and cash flows for the year then ended. These financial statements are the responsibility of the Fund's Management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards required that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2001 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2000 and 1999 and for the years then ended are the financial statements of EnerMark Income Fund (See Note 1 to the financial statements). These financial statements were audited by other auditors who expressed an opinion without reservation on those consolidated financial statements in their report dated March 14, 2001. The opinion of such auditors, however, did not cover the reconciliation of differences between Canadian and United States generally accepted accounting principles as disclosed in Note 10. We have audited the reconciliations pertaining to 2000 and 1999. In our opinion, the reconciliations are appropriate and have been presented on a basis consistent with the current year.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP
Chartered Accountants

Calgary, Alberta
March 1, 2002

ENERPLUS RESOURCES FUND

CONSOLIDATED BALANCE SHEET

As at December 31 ($thousands)	2001	2000	1999
		(Note 1)	(Note 1)
ASSETS			
Current assets			
Cash and cash equivalents	**$ 979**	$ 846	$ 2,482
Accounts receivable	**100,089**	77,086	15,506
Other	**4,869**	6,474	1,365
	105,937	84,406	19,353
Property, plant and equipment	**2,667,504**	1,791,649	789,174
Accumulated depletion and depreciation	**(489,188)**	(308,356)	(232,889)
	2,178,316	1,483,293	556,285
Deferred reorganization charges, net of amortization (Note 2)	**-**	253	1,263
	$ 2,284,253	$ 1,567,952	$ 576,901
LIABILITIES AND EQUITY			
Current liabilities			
Accounts payable	**$ 72,341**	$ 91,135	$ 19,705
Distributions payable to Unitholders (Note 9)	**20,860**	18,925	7,547
Payable to related company (Note 6)	**7,915**	14,222	2,852
	101,116	124,282	30,104
Bank debt (Note 3)	**412,589**	275,944	131,315
Future income taxes (Note 5)	**333,560**	353,115	33,593
Accumulated site restoration	**55,403**	37,596	14,035
Deferred credits (Note 2)	**6,591**	-	-
Payable to related party (Note 6)	**1,909**	-	-
Non-controlling interest (Note 7)	**-**	25,013	-
	810,052	691,668	178,943
EQUITY			
Unitholders' capital (Note 4)	**1,826,507**	1,054,859	592,693
Accumulated income	**324,570**	144,301	78,328
Accumulated cash distributions (Note 9)	**(777,992)**	(447,158)	(303,167)
	1,373,085	752,002	367,854
	$ 2,284,253	$ 1,567,952	$ 576,901

Signed on behalf of the Board:

Douglas R. Martin
Director

Robert L. Normand
Director

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF INCOME

For the year ended December 31 ($thousands except per Unit amounts)	2001	2000	1999
		(Note 1)	(Note 1)
REVENUES			
Oil and gas sales	$ 639,379	$ 343,182	$ 169,541
Crown royalties	(101,114)	(65,451)	(23,902)
Freehold and other royalties	(31,546)	(15,492)	(8,243)
	506,719	262,239	137,396
Interest and other income	858	611	1,045
	507,577	262,850	138,441
EXPENSES			
Operating	120,082	54,997	37,228
General and administrative	12,971	7,202	5,726
Management fee (Note 6)	9,323	4,556	2,204
Interest (Note 3)	17,605	15,322	9,078
Depletion, depreciation and amortization	194,080	80,309	61,857
	354,061	162,386	116,093
Income before taxes	153,516	100,464	22,348
Capital taxes	4,722	2,936	1,551
Future income tax provision (recovery) (Note 5)	(31,475)	15,378	(4,957)
	(26,753)	18,314	(3,406)
NET INCOME	$ 180,269	$ 82,150	$ 25,754
Net income per Trust Unit			
Basic	$ 3.28	$ 3.06	$ 1.25
Diluted	$ 3.28	$ 3.05	$ 1.25
Weighted average number of			
Trust Units outstanding (thousands)			
Basic	54,907	26,841	20,532
Diluted	54,956	26,928	20,607

CONSOLIDATED STATEMENT OF ACCUMULATED INCOME

For the year ended December 31 ($thousands)	2001	2000	1999
		(Note 1)	(Note 1)
Accumulated income, beginning of year	$ 144,301	$ 78,328	$ 52,574
Change in accounting policy (Note 2)	-	(16,177)	-
Net income	180,269	82,150	25,754
Accumulated income, end of year	$ 324,570	$ 144,301	$ 78,328

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31 ($thousands)	2001	2000	1999
		(Note 1)	(Note 1)
OPERATING ACTIVITIES			
Net income	**$ 180,269**	$ 82,150	$ 25,754
Depletion, depreciation and amortization	**194,080**	80,309	61,857
Future income taxes (recovery) (Note 5)	**(31,475)**	15,378	(4,957)
Site restoration and abandonment costs incurred	**(2,628)**	(1,471)	(1,124)
Gain on sale of investment	**-**	-	(565)
Funds flow from operations	**340,246**	176,366	80,965
Decrease (increase) in non-cash operating working capital	**(52,928)**	(11,354)	32
	287,318	165,012	80,997
FINANCING ACTIVITIES			
Issue of Trust Units, net of issue costs (Note 4)	**151,411**	120,600	54,689
Cash distributions to Unitholders	**(328,899)**	(132,613)	(70,603)
Bank debt (payments) proceeds	**58,021**	77,765	(53,579)
	(119,467)	65,752	(69,493)
INVESTING ACTIVITIES			
Property, plant and equipment	**(228,345)**	(64,984)	(25,509)
Proceeds on sale of property, plant and equipment	**75,276**	18,481	16,957
Corporate acquisitions (Notes 1 and 7)	**(14,649)**	(186,897)	(2,925)
Proceeds on sale of investments	**-**	1,000	773
	(167,718)	(232,400)	(10,704)
Increase (decrease) in cash	**133**	(1,636)	800
Cash, beginning of year	**846**	2,482	1,682
Cash, end of year	**$ 979**	$ 846	$ 2,482
SUPPLEMENTARY CASH FLOW INFORMATION			
Cash income taxes paid	**$ -**	$ -	$ -
Cash interest paid	**$ 17,162**	$ 15,199	$ 9,001

CONSOLIDATED STATEMENT OF ACCUMULATED CASH DISTRIBUTIONS

For the year ended December 31 ($thousands)	2001	2000	1999
		(Note 1)	(Note 1)
Accumulated cash distributions, beginning of year	**$ 447,158**	$ 303,167	$ 228,272
Cash distributions	**330,834**	143,991	74,895
Accumulated cash distributions, end of year (Note 9)	**$ 777,992**	$ 447,158	$ 303,167

ENERPLUS RESOURCES FUND

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS DECEMBER 31, 2001, 2000 AND 1999

(Tabular amounts in thousands of Canadian dollars and thousands of Units except per Unit amounts)

1. ACQUISITION OF ENERPLUS RESOURCES FUND

The Merger of EnerMark Income Fund ("EnerMark") and Enerplus Resources Fund ("Enerplus" or the "Fund") which occurred on June 21, 2001 ("Merger") was accounted for as a reverse takeover as the Unitholders of EnerMark became the controlling Unitholders of the Fund after the Merger. Under this form of purchase accounting, EnerMark is deemed to have acquired Enerplus and the consolidated financial statements of the Fund for the year ended December 31, 2001 include only EnerMark's operating results prior to the Merger and the results of the merged Fund thereafter. All comparative figures and references to prior years are those of EnerMark. All disclosures of Trust Units, warrants and options and per Unit data up to June 21, 2001 Merger date have been restated using the Merger exchange ratio of 0.173 Enerplus Unit for each EnerMark Unit (the "Merger Exchange Ratio").

EnerMark is deemed to have acquired all of the outstanding Trust Units of Enerplus on June 21, 2001 for fair market value consideration totalling $600,745,000. The 20,863,000 Trust Units of Enerplus which were outstanding prior to the Merger were recorded as deemed consideration at a value of $582,817,000 representing an exchange value of $27.94 per Trust Unit. In addition, costs and other charges of $17,928,000 related to the acquisition were recorded.

The net assets acquired and liabilities assumed are as follows:

Property, plant and equipment	$ 704,838
Working capital deficiency	(10,415)
Long-term debt assumed	(78,624)
Site restoration and abandonment	(14,530)
Future income taxes	(524)
Net assets acquired	$ 600,745

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Management of Enerplus prepares the financial statements following Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc., its wholly-owned subsidiary Enerplus Resources Corporation ("ERC") and CIBC Mellon Trust Company as Trustee. The beneficiaries of the Fund (the "Unitholders") are holders of Trust Units (the "Trust Units") issued by the Fund . The Fund is a limited-purpose trust whose purpose is to invest in securities of its wholly-owned subsidiary EnerMark Inc., invest in royalties granted by EnerMark Inc. and ERC, administer the assets and liabilities of the Fund and make distributions to the Unitholders.

The Fund's financial statements include the accounts of the Fund, EnerMark Inc. and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated.

(b) Property, Plant and Equipment

Oil and Natural Gas

The Fund follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements which extend the recoverable reserves of the property, plant and equipment are capitalized. During 2001, general and administrative costs of $7,547,000 (2000 - $7,925,000, 1999 - $3,734,000) were capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would significantly alter the rate of depletion.

Other Equipment

All other equipment is carried at cost and is depreciated over the estimated useful lives of the assets at annual rates varying from 10% to 30%.

(c) Ceiling Test

The Fund places a limit on the aggregate cost of property, plant and equipment, which may be carried forward for amortization against revenues of future periods (the "Ceiling Test"). The Ceiling Test is a cost recovery test whereby the capitalized costs less accumulated depletion and depreciation, accumulated site restoration and future income taxes are limited to an amount equal to estimated undiscounted future net revenues from proven reserves, plus the unimpaired costs of non-producing properties, less estimated future general and administrative expenses, site restoration costs, management fees, financing costs and capital taxes. Costs and prices at the balance sheet date are used in determining Ceiling Test amounts. Any costs carried on the balance sheet in excess of the Ceiling Test limitation are charged to earnings.

(d) Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated using the unit-of-production method based on the Fund's share of estimated proven reserves before royalties. Reserves are converted to equivalent units on the basis of approximate relative energy content based on the Fund's share of estimated proven reserves before royalties.

(e) Site Restoration and Abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method and is included in depletion, depreciation and amortization expense. Actual site restoration costs are charged against the accumulated liability.

(f) Joint Venture

Substantially all oil and natural gas production activities are conducted jointly with others. Accordingly, the accounts reflect the Fund's proportionate interest in these activities.

(g) Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Unitholders. As the Fund distributes all of its taxable income to the Unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Fund, no provision for income tax has been made in the Fund.

The Fund follows the liability method of accounting for income taxes. Under this methodology, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Fund's corporate subsidiaries and their respective tax bases, using substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(h) Deferred Reorganization Charges

Deferred reorganization charges were related to the inception of EnerMark and have been amortized over a five-year period ended March 31, 2001.

(i) Deferred Credits

The deferred credits are costs associated with the mark-to-market valuation of Enerplus' natural gas price foward contracts which were "out-of-the-money" at the date of the Merger. This deferred credit will be amortized to income over the life of the natural gas financial contract ending October 31, 2004.

(j) Financial Instruments

The Fund uses various financial instruments to manage risks associated with crude oil and natural gas price fluctuations and to manage interest rates. The instruments are not used for trading purposes and constitute effective hedges. Proceeds and costs realized from holding the crude oil and natural gas contracts are recognized in oil and gas revenues at the time each transaction under a contract is settled. The costs or proceeds realized from holding the interest rate swaps are recognized in interest expense at the time each transaction is settled.

(k) Cash and Cash Equivalents

The Fund considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of funds on deposit under various terms. Cash and cash equivalents are stated at cost which approximates fair value.

(l) Change in Accounting Policy

Effective January 1, 2000 the Fund, on a retroactive basis, adopted the liability method of accounting for income taxes in accordance with the new Canadian Institute of Chartered Accountants income tax standard. The cumulative effect as at January 1, 2000 was to increase future income taxes payable and decrease accumulated income by $16,177,000. The 1999 financial statements have not been restated for the change. The new recommendations do not affect the Fund's cash flow or liquidity.

3. BANK DEBT

As at December 31, 2001 Enerplus had banking arrangements for each of ERC and EnerMark Inc. under separate, syndicated, revolving, extendible production and operating facilities (the "Facilities") in an aggregate amount of $585,000,000 (2000 - $420,000,000, 1999 - $200,000,000). The Facilities were secured by fixed and floating charge debentures on substantially all of the assets held by EnerMark Inc. and ERC.

The terms of the banking arrangements provided Enerplus with various borrowing options including prime rate based advances and bankers acceptances. The average borrowing rate for the year ended December 31, 2001 was 2.98%. Interest on the bank loan amounted to $17,346,000 in 2001 (2000 - $14,418,000, 1999 - $9,031,000).

As at March 1, 2002, Enerplus renegotiated the Facilities into a single syndicated facility (the "Combined Facility") in the amount of $620,000,000 which will be reviewed on May 31, 2002 and annually on May 31 of each year, thereafter. The Combined Facility is unsecured and consists of a $590,000,000, 364 day revolving committed line, with an incremental two year term and a $30,000,000 demand operating line. As with the former Facilities, the Combined Facility allows various borrowing options including prime rate based advances and banker's acceptances.

In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, Enerplus will be required to maintain certain minimum balances on deposit with the syndicate agent.

The Combined Facility is the legal obligation of EnerMark Inc. and is guaranteed by ERC. Although payments to Unitholders are subordinated to the Combined Facility, Unitholders have no direct liability to EnerMark Inc. or ERC should their revenues be insufficient to repay the bank loan. However, the bank debt has priority over claims of and distributions to the Unitholders.

Since a demand for payment, with respect to the operating facility, would be financed by the revolving facility, no portion of the operating facility has been considered as current.

4. FUND CAPITAL

(a) Unitholders' Capital

Trust Units

Authorized: Unlimited Number of Trust Units

Issued:	**2001**		2000		1999	
(thousands)	**Units**	**Amount**	Units	Amount	Units	Amount
Balance, beginning of year	**40,925**	**$1,050,986**	21,761	$ 592,693	18,540	$ 538,004
Issued for cash:						
Pursuant to public offerings	**4,313**	**101,039**	4,576	109,835	2,860	47,952
Pursuant to Option Plans	**135**	**2,530**	128	2,125	29	419
Pursuant to the exercise of warrants	**1,197**	**33,319**	17	404	-	-
Pursuant to the expiry of warrants	**-**	**2,846**	-	-	-	-
Issued pursuant to the deemed acquisition of Enerplus (Note 1)	**20,863**	**582,364**	-	-	-	-
Issued pursuant to the management agreement (Note 6)	**173**	**5,000**	-	-	-	-
Distribution Reinvestment Plan	**659**	**16,577**	407	9,314	332	6,319
Corporate acquisitions (Note 7)						
Cabre Exploration Ltd.	**1,267**	**31,846**	9,897	248,825	-	-
Western Star Exploration Ltd.	-	-	13	65	-	-
Pursuit Resources Corp.	-	-	2,988	64,228	-	-
Acquisition of property interests	-	-	1,138	23,509	-	-
Redeemed for cash	-	-	-	(12)	-	(1)
Balance, end of year	**69,532**	**$ 1,826,507**	40,925	$ 1,050,986	21,761	$ 592,693

Warrants	2001		2000		1999	
(thousands)	**Warrants**	**Amount**	Warrants	Amount	Warrants	Amount
Balance, beginning of year	**3,045**	**$ 3,873**	-	$ -	-	$ -
Issued during the year	**390**	**496**	3,065	3,873	-	-
Exercised during the year	**(1,197)**	**(1,523)**	(17)	-	-	-
Expired during the year	**(2,238)**	**(2,846)**	(3)	-	-	-
Balance, end of year	**-**	**-**	3,045	$ 3,873	-	-

On November 15, 2001, the Fund issued 4,312,500 Trust Units at a price of $24.75 per Trust Unit, pursuant to a short form prospectus to raise gross proceeds of $106,734,000 ($101,039,000 net of issuance costs).

In accordance with the reverse takeover method of purchase accounting, as described in Note 1, Trust Units and warrant amounts are those of EnerMark to June 21, 2001 together with changes in consolidated capital since that date. Numbers of Trust Units and Warrants issued to June 21, 2001 have been restated on the basis of the Merger Exchange Ratio. In addition, EnerMark is deemed to have acquired the net assets of Enerplus, in exchange for the 20,863,000 Trust Units of the Fund which were outstanding at June 21, 2001, the date of the acquisition. The deemed Trust Unit gross consideration was recorded in the amount of $582,817,000 ($582,364,000 net of issuance costs).

Under the terms of an agreement for the provision of management, advisory and administrative services with a related party (Note 6), the Fund issued 172,500 Trust Units at a recorded value of $5,000,000.

Pursuant to an offer to purchase, which initially expired on December 21, 2000, and was subsequently extended, to January 8, 2001, the Fund acquired all of the outstanding common shares of Cabre Exploration Ltd. ("Cabre") (Note 7). As at December 31, 2000, the Fund had completed the acquisition of an 88.65% controlling interest in Cabre. The consideration for the controlling interest included the issuance of 9,897,000 Trust Units at $25.20 per Trust Unit for a value of $249,434,000 ($248,825,000 net of issuance costs) and 3,045,000 warrants at $1.27 per warrant for an ascribed value of $3,873,000. The warrants were exercisable into one Trust Unit at a price of $26.53 per Trust Unit at any time, until December 17, 2001.

The acquisition of the remaining 11.35% non-controlling interest of Cabre was completed on January 8, 2001 and resulted in the issuance of 1,267,000 additional Trust Units, at $25.20 per Trust Unit for gross consideration of $31,924,000 ($31,846,000 net of issuance costs) and 390,000 additional warrants at $1.27 per warrant for an ascribed value of $496,000.

On September 12, 2000, the Fund completed an offering of 4,575,850 Trust Units, at a price of $25.14 per Trust Unit, pursuant to a short form prospectus to raise gross proceeds of $115,061,000 ($109,835,000 net of issuance costs). The net proceeds of the offering were used to repay a portion of bank indebtedness incurred in connection with the acquisition of EBOC Energy Ltd. (Note 7).

On April 3, 2000, under the terms of an offer to purchase, the Fund successfully acquired Pursuit Resources Corp. (Note 7). The total consideration included the issuance of 2,988,000 Trust Units at $21.68 per Trust Unit for a value of $64,779,000 ($64,228,000 net of issuance costs).

On February 28, 2000, the Fund completed the acquisition of various property interests in the Hanna, Alberta area from an affiliate of a major Canadian pension fund. Consideration paid for the property interests included the issuance of 1,046,000 Trust Units recorded at $20.23 per Trust Unit. In addition, on August 30, 2000, the Fund acquired various property interests from two private corporations in exchange for 92,000 Trust Units valued at $25.78 per Trust Unit. Gross consideration for these acquisitions totalled $23,539,000 ($23,509,000 net of issuance costs).

Pursuant to an offer to purchase which was completed on January 7, 2000, the Fund acquired all of the issued and outstanding common shares of Western Star Exploration Ltd. (Note 7). The total consideration paid included the issuance of 12,874 Trust Units recorded at $21.67 per Trust Unit, for gross consideration of $279,000 ($65,000 net of issuance costs). Total consideration also included the issuance of 20,000 warrants. Each warrant was exercisable into one Trust Unit at a price of $23.12 per Trust Unit at any time until December 31, 2000, at which time 3,000 of the warrants outstanding expired.

Pursuant to an offering, which closed August 26, 1999, the Fund issued 1,211,000 Units at a price of $21.97 per Unit for gross proceeds of $26,606,000 ($25,076,000 net of issuance costs).

In February 1999 the Fund issued 1,649,000 Units at a price of $14.16 per Unit pursuant to an Offer of Rights to subscribe for Trust Units which expired February 26, 1999 for gross proceeds of $23,350,000 ($22,876,000 net of issuance costs).

In each of 2001, 2000, and 1999, Enerplus entered into joint venture agreements (the "Arrangements") with independent corporations (the "Corporations") whose sole purpose is to hold oil and natural gas interests earned under each Arrangement. The terms of the Arrangements require the Corporations to commit funds to be spent in joint venture with Enerplus as specified below. In addition, each Corporation has been granted the option to put its common shares to Enerplus at their fair value as determined by an independent evaluator on specified dates (the "Specified Dates"). Enerplus may elect to pay for the shares by way of cash or through the issuance of Trust Units of the Fund. If Trust Units are issued they are to be valued at 95% of their average closing price, for the 60 day period preceding the specified dates.

Drilling Fund Corporations	Approximate Funding Commitment	Specified Date
2001 Arrangement	$2.7 million	March 1, 2004
2000 Arrangement	$5.4 million	February 1, 2003
1999 Arrangement	$2.7 million	February 1, 2002

As at the date of preparation of these consolidated financial statements, the Corporation involved in the 1999 Arrangement may exercise its option to put its common shares to Enerplus. Enerplus has the option to acquire the shares of the Corporation for cash or through the issuance of Trust Units.

Trust Units are redeemable at any time, on demand by Unitholders, at 85% of the market price in effect from time to time. Redemptions cannot exceed $500,000 during any calendar month.

Pursuant to a revised monthly Distribution Reinvestment and Unit Purchase Plan, which became effective on March 30, 2001, Unitholders are entitled to reinvest cash distributions in additional Units of the Fund. Units are issued at a discount of 5% below the weighted average market price on the Toronto Stock Exchange for the twenty trading days preceding a distribution payment date and without service charges or brokerage fees. Unitholders are also entitled to make optional cash payments to acquire additional Units. Units issued pursuant to optional cash payments are issued on the same basis as reinvested cash distributions except no discount applies.

(b) Trust Unit Option Plan

On August 22, 1996, a special resolution was passed approving the EnerMark Trust Unit Option Plan for trustees, directors, officers, employees of EnerMark or its affiliates, and related parties involved with the management of EnerMark. Enerplus had a similar plan for its directors, officers and employees. On June 21, 2001, in connection with the Merger, the vesting of certain EnerMark Trust Unit options was accelerated and the equivalent of in-the-money amounts on such vested options were paid out and have been included as a cost of the acquisition of Enerplus (Note 1). All outstanding EnerMark Trust Unit options were then cancelled and the 363,000 Enerplus Trust Unit Options outstanding as at June 21, 2001 were assumed.

Activity for the options issued pursuant to Option Plans are summarized as follows:

	2001		2000		1999	
(thousands except per Unit amounts)	**Number Of Options**	**Weighted Average Exercise Price**	Number Of Options	Weighted Average Exercise Price	Number Of Options	Weighted Average Exercise Price
EnerMark Unit Options outstanding						
beginning of year	**609**	**$ 24.28**	740	$ 28.32	814	$37.05
Granted	**639**	**$ 26.53**	294	$ 22.31	318	$14.62
Exercised	**(80)**	**$ 17.98**	(128)	$ 16.59	(29)	$14.62
Cancelled	**(321)**	**$ 26.47**	(297)	$ 35.84	(363)	$36.94
Accelerated due to Merger	**(847)**	**$ 25.72**				
Enerplus Unit Options outstanding						
at June 21, 2001	**363**	**$ 21.03**	-		-	
Exercised	**(55)**	**$ 21.94**	-		-	
Cancelled	**(44)**	**$ 20.47**	-		-	
Outstanding at end of year	**264**	**$ 20.93**	609	$ 24.28	740	$28.32
Balance of Trust Units						
reserved but not issued	-		1,852		349	
Total Trust Units reserved						
as at the end of the year	**264**		2,461		1,089	

The following table summarizes information with respect to outstanding Unit Options as at December 31, 2001:

Number Outstanding At December 31, 2001 (thousands)	Exercise prices	Expiry Date December 31	Number Exercisable December 31, 2001 (thousands)
27	$15.30	2002	27
52	$17.10	2003	23
185	$22.90	2004	49
264	$20.93		99

(c) Trust Unit Rights Incentive Plan

On June 21, 2001, a special resolution was passed to approve the adoption of a Trust Unit Rights Incentive Plan ("Incentive Plan") pursuant to which rights to acquire Enerplus Trust Units may be granted to trustees, directors, officers, employees, of the Fund or its affiliates and related parties involved in the management of the Fund. Under the Incentive Plan, distributions per Trust Unit to Enerplus Unitholders in a calendar quarter which represent a return of more than 2.5% of the net property, plant and equipment of Enerplus at the end of such calendar quarter would result in a reduction in the exercise price of the Rights. No such reductions have occurred in 2001.

Activity for the options issued pursuant to the Incentive Plan is as follows:

(thousands except per Unit amounts)	2001 Number of Rights	2001 Exercise Price	2000 Number of Rights	2000 Exercise Price	1999 Number of Rights	1999 Exercise Price
Incentive Plan Rights outstanding beginning of year	-	-	-	-	-	-
Granted	1,360	$ 24.50	-	-	-	-
Cancelled	(42)	$ 24.50	-	-	-	-
Outstanding at end of year	1,318	$ 24.50	-	-	-	-
Balance of Trust Units reserved but not issued	1,422					
Total Trust Units reserved at the end of the year	2,740		-		-	
Exercisable at December 31, 2001	-		-		-	

5. INCOME TAXES

(a) The Fund

The Fund is an inter vivos trust for income tax purposes. As such, the Fund is taxable on any income which is not allocated to the Unitholders. The Fund intends to allocate all income to Unitholders. Should the Fund incur any income taxes, the funds available for distribution will be reduced accordingly.

During 2001, the Fund had taxable income of $181.3 million (2000 - $69.1 million and 1999 - $20.0 million) or $4.71 per Unit (2000 - $2.44 per Unit and 1999 - $0.956 per Unit) which was allocated to the Unitholders. Taxable income of the Fund is comprised of income on securities issued by EnerMark and royalty income, less deductions for Canadian oil and gas property expense ("COGPE"), which is claimed at a rate of 10% on a declining balance basis and the allowable portion of the cost of issuing new Trust Units during the period. Any losses which occur in the Fund must be retained in the Fund and may be carried forward and deducted from taxable income for a period of seven years. As at December 31, 2001, the Fund had no losses available for carry forward.

The amounts of COGPE and issue costs remaining in the Fund are as follows:

	2001 Per Unit	2001 Amount	2000 Per Unit	2000 Amount	1999 Per Unit	1999 Amount
COGPE	$ 5.49	$ 381,563	$ 2.14	$ 87,294	$ 4.45	$ 96,993
Issue costs	0.14	10,063	0.17	7,681	0.23	4,800
Total	$ 5.63	$ 391,626	$ 2.31	$ 94,975	$ 4.68	$ 101,793

(b) Corporate Subsidiaries

The provision for future income taxes arises from temporary differences in the recognition of revenues and expenses for income tax and accounting purposes. The temporary differences, tax effected at substantially enacted rates, comprising the future income tax liability are as follows:

	2001	2000
Excess of net book value of property, plant and equipment over the underlying tax basis	**$ 350,754**	$ 367,486
Future site restoration deductions	**(17,643)**	(14,318)
Other	**449**	(53)
Future income tax liability	**$ 333,560**	$ 353,115

The provisions for income taxes vary from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

	2001	2000	1999 [1]
Net income before taxes	**$ 153,516**	$ 100,464	$ 22,348
Computed income tax expense (recovery) at substantially enacted rates of 42.62% (44.62% for 2000 and 1999)	**$ 65,429**	$ 44,827	$ 9,972
Increase (decrease) resulting from:			
Net income attributed to the Fund	**(95,671)**	(32,173)	(14,755)
Non-deductible crown royalties and other payments	**43,309**	29,166	11,279
Federal resource allowance	**(43,658)**	(26,975)	(9,935)
Non-deductible depletion	**-**	-	1,176
ARTC	**(214)**	(249)	(614)
Other	**(670)**	782	(2,080)
Future income taxes (recovery)	**$ (31,475)**	$ 15,378	$ (4,957)

[1] See Note 2 (l)

6. RELATED PARTY TRANSACTIONS

Management, advisory and administration services are supplied to the Fund on a fee and cost reimbursement basis, pursuant to a new agreement with Enerplus Global Energy Management Company ("EGEM"), commencing on June 21, 2001, and prior thereto with EMR Resource Management Ltd., a wholly-owned subsidiary of EGEM. As at December 31, 2001, $7,406,000 was payable to EGEM, pursuant to this agreement.

Management fees equal to 2.2% of operating income to June 21, 2001 and 2.75%, thereafter, are reported on the Consolidated Statement of Income. Pursuant to the agreement, prior to June 21, 2001, fees of $302,000 earned in relation to certain property acquisitions and divestitures of Enerplus which are included in the cost of property, plant and equipment. Under the new agreement, acquisition and divestment fees were eliminated and replaced with a performance fee based on both the total return of the Fund and its relative performance, as compared to other senior Canadian conventional oil and gas energy funds. For the year ended December 31, 2001, no amounts for performance fees are included in the determination of management fees as reported on the Consolidated Statement of Income. In conjunction with the Merger, EGEM received a minimum fee of 172,500 Enerplus Trust Units with an assigned value of $5,000,000. The fee was accounted for as a cost of the Merger.

Pursuant to a share purchase agreement related to the Merger, EnerMark Inc. acquired all of the outstanding common shares of ERC from EGEM resulting in ERC becoming a wholly-owned subsidiary of Enerplus. Consideration for the shares was $2,545,000 and is payable over a five year period ending September 2006, through a reduction in management fees. Of this amount, $509,000 has been classified as a current liability. The non-refundable fee advance and acquisition cost of the ERC shares has been included as a cost of the acquisition of Enerplus Resources Fund.

In addition to the transactions described above, Enerplus has entered into a financial instrument contract with an indirect subsidiary of El Paso Energy Corporation, the ultimate parent of EGEM, as described in Note 8.

7. CORPORATE ACQUISITIONS

(a) Cabre Exploration Ltd.

Pursuant to an offer to purchase, initially expiring December 21, 2000 and subsequently extended to January 8, 2001, Enerplus acquired all of the outstanding common shares of Cabre Exploration Ltd. ("Cabre") a public Alberta corporation, of which Enerplus held an 88.65% controlling interest as at December 31, 2000.

The 88.65% controlling interest in Cabre was acquired for a total consideration of $259,878,000 which consisted of 9,897,000 Trust Units with a recorded value of $249,434,000, costs associated with the acquisition of $6,571,000 and 3,045,000 warrants excercisable into one Trust Unit at a price of $26.53 until December 17, 2001 with a recorded value of $3,873,000. A future tax cost of $46,077,000 plus an amount of $64,510,000 by which the total consideration exceeded the proportionate carrying value recorded in the accounts of Cabre has been allocated as an increase to property, plant and equipment.

The acquisition of the remaining 11.35% in common shares of Cabre was completed on January 8, 2001 for a total consideration of $32,420,000 which consisted of 1,267,000 Trust Units with a recorded value of $31,924,000 and 390,000 warrants excercisable into one Trust Unit at a price of $26.53 until December 17, 2001 with a recorded value of $496,000. A future tax cost of $11,396,000 plus an amount of $7,407,000 by which the total consideration exceeded the proportionate carrying value recorded in the accounts of Cabre has been allocated as an increase to property, plant and equipment.

The net assets acquired and liabilities assumed for the completed acquisition are summarized as follows:

	88.65% December 31 2000	11.35% January 8 2001	100.00% Total
Property, plant and equipment	$ 484,550	$ 18,803	$ 503,353
Working capital deficiency	(21,424)	-	(21,424)
Long-term debt assumed	(18,213)	-	(18,213)
Site restoration and abandonment	(19,196)	-	(19,196)
Future income taxes	(140,826)	(11,396)	(152,222)
Non-controlling interest	(25,013)	25,013	-
Net assets required	**$ 259,878**	**$ 32,420**	**$ 292,298**

Cabre was formally amalgamated effective January 17, 2001 with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(b) EBOC Energy Ltd.

On September 1, 2000, the Fund acquired all outstanding common shares of EBOC Energy Ltd. ("EBOC") a private Alberta corporation for total consideration of $148,217,000 comprised of $143,585,000 in cash and related costs of $4,632,000. A future income tax cost of $84,882,000 plus an amount of $105,761,000 by which the total consideration paid exceeded the carrying value recorded in the accounts of EBOC has been allocated as an increase to property, plant and equipment. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$ 263,608
Working capital deficiency	(2,947)
Long-term debt assumed	(6,428)
Site restoration and abandonment	(287)
Future income taxes	(105,729)
Net assets acquired	**$ 148,217**

EBOC was amalgamated effective September 1, 2000 with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(c) Pursuit Resources Corp.

Pursuant to a takeover bid which was completed on April 3, 2000, the Fund acquired all outstanding common shares of Pursuit Resources Corp. ("Pursuit") a public Alberta corporation. The total consideration of $81,670,000 consisted of 2,988,000 Trust Units of the Fund with a recorded value of $64,779,000, cash of $14,693,000 and costs associated with the acquisition in the amount of $2,198,000. A future income tax cost of $29,821,000 plus an amount of $37,060,000 by which the total consideration paid exceeded the carrying value recorded in the accounts of Pursuit has been allocated as an increase to property, plant and equipment. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$159,213
Working capital	1,079
Long-term debt assumed	(37,195)
Site restoration and abandonment	(1,381)
Future income taxes	(40,046)
Net assets acquired	**$ 81,670**

Pursuit remained a wholly-owned subsidiary of EnerMark Inc. until July 1, 2000 when it was amalgamated with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(d) Western Star Exploration Ltd.

Pursuant to a takeover bid which was completed on January 7, 2000, the Fund acquired all outstanding common shares of Western Star Exploration Ltd. ("Western Star") a public Alberta corporation. The total consideration of $22,035,000 consisted of 12,874 Trust Units of the Fund with a recorded value of $279,000, cash of $21,251,000 and related costs of $505,000. Recipients of Trust Units also received 20,000 warrants, which were exercisable into one Trust Unit at a price of $23.12 per Trust Unit until December 31, 2000. The total consideration paid in excess of the carrying value recorded in the accounts of Western Star has been allocated as an increase to property, plant and equipment in the amount of $8,400,000. The net assets acquired and liabilities are summarized as follows:

Property, plant and equipment	$ 27,894
Working capital deficiency	(495)
Long-term debt assumed	(5,028)
Site restoration and abandonment	(336)
Net assets acquired	**$ 22,035**

Western Star remained a wholly-owned subsidiary of EnerMark Inc. until April 1, 2000 when it was amalgamated with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(e) Derrick Energy Corporation

Pursuant to a plan of arrangement which closed June 4, 1999, the Fund acquired all of the outstanding shares of Derrick Energy Corporation ("Derrick"), a public Alberta corporation, and immediately thereafter disposed of 80% of Derrick's petroleum and natural gas assets to predecessor companies of ERC. The total net consideration of $2,925,000 consisted of $26,888,000 in cash and $73,000 in costs associated with the arrangement less disposal proceeds of $24,036,000. The carrying value recorded in the accounts of Derrick exceeded the total consideration paid net of disposal proceeds by $2,575,000 and has been allocated as a decrease to property, plant and equipment. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$ 3,748
Working capital deficiency	(776)
Site restoration and abandonment	(47)
Net assets acquired	**$ 2,925**

Derrick remained a wholly-owned subsidiary of EnerMark Inc. until January 1, 2000 when it was amalgamated with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

8. FINANCIAL INSTRUMENTS

The Fund's financial instruments that are included in the balance sheet are comprised of current assets, current liabilities, the bank debt and the long-term payable to related party.

The fair market values of these instruments approximate their carrying amount due to the short-term maturity of these instruments and the variable interest rates applied to the bank debt. Virtually all of the Fund's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

The Fund uses various types of financial instruments to manage the risk related to fluctuating commodity prices. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle these instruments as at December 31, 2001. The Fund may be exposed to losses in the event of default by the counterparties to these instruments. This credit risk is controlled by the Fund through the selection of financially sound counterparties.

CRUDE OIL

As at December 31, 2001 Enerplus has three separate three-way financial option transactions that are designed to reduce a downward impact of crude oil prices on 3,675 bbls/day of crude oil production. The total cost to be amortized in 2002 is $859,000. The fair value of the financial crude oil hedges as at December 31, 2001 reflects an unrealized gain of $274,000.

		WTI US$/bbl		
Financial Instrument Type	Daily Volumes bbls/day	Sold Call	Purchased Put	Sold Put
Crude Oil 2002				
Financial Contracts				
3-Way option	1,500	$ 27.00	$ 19.50	$ 16.00
3-Way option [1]	1,500	$ 25.00	$ 19.50	$ 17.00
3-Way option	675	$ 27.00	$ 19.50	$ 17.00
Total	**3,675**			

[1] The counterparty to one of the 3-way crude oil options above, is a subsidiary of El Paso Energy Corporation which is the ultimate parent of EGEM (refer to Note 6). The remaining option premiums for these instruments are $276,000 and are being amortized over their remaining terms.

NATURAL GAS

As at December 31, 2001 Enerplus has physical and financial contracts in place on approximately 57 MMcf/day of natural gas in 2002 and 20 MMcf/day of natural gas in 2003. The remaining costs to be amortized in 2002 are $2,032,000 and $1,696,000 in 2003. The fair value of the financial natural gas hedges as at December 31, 2001 reflects an unrealized loss of $711,000.

The following table summarizes the commodity risk management positions as at December 31, 2001:

	Annualized	AECO $/Mcf				
	Daily Volumes	Sold	Purchased	Sold	Fixed	Escalated
Financial Instrument Type	Mcf/d	Call	Put	Put	Price	Price
Natural Gas 2002						
Physical contracts	6,002	-	-	-	$ 2.64	-
Physical contracts	1,967	-	-	-	-	$2.01
	7,969					
Financial contracts						
Collar [1]	9,084	$ 5.27	$ 3.69	-	-	-
Put [1]	9,084	-	$ 3.69	-	-	-
Swap	3,792	-	$ 2.90	-	-	-
Collar	7,584	$ 4.22	$ 3.43	-	-	-
Collar	5,688	$ 4.81	$ 3.43	-	-	-
Collar	14,220	$ 4.22	$ 3.32	-	-	-
Total	57,421					
Natural Gas 2003						
Physical contracts	2,369	-	-	-	$ 2.64	-
Physical contracts	1,967	-	-	-	-	$ 2.23
	4,336					
Financial contracts						
Collar [1]	5,922	$ 5.27	$ 3.69	-	-	-
Put [1]	5,922	-	$ 3.69	-	-	-
Swap	3,792	-	$ 2.90	-	-	-
Total	19,972					
Natural Gas 2004						
Physical contracts	1,967	-	-	-	-	$ 2.33
Financial contracts swaps	3,160	-	$ 2.90	-	-	-
Total	5,127					
Natural Gas 2005 - 2010						
Physical	1,967	-	-	-	-	$ 2.43

(1) The counterparty to these natural gas collars and puts, is a subsidiary of El Paso Energy Corporation which is the ultimate parent of EGEM (refer to Note 6). The option premiums for these instruments are $3,728,000 and are being amortized over their remaining terms.

9. RESTATEMENT OF PRIOR YEARS DISTRIBUTION PAYABLE TO UNITHOLDERS

The comparative consolidated balance sheets for December 31, 2000 and 1999 and consolidated statements of accumulated cash distributions for each of the years then ended have been restated to recognize a current liability to Unitholders representing the monthly distribution that was declared on December 20, 2000 and December 20, 1999 and paid on January 20, 2001 and January 20, 2000, respectively. The effect of this change is to increase distributions payable to Unitholders and increase accumulated cash distributions by $18,925,000 and $7,547,000 as at December 31, 2000 and 1999, respectively. There is no current or prior effect to the Fund's cash flow or earnings.

10. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Fund's consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles, as they pertain to the Fund's consolidated statements, differ from United States generally accepted accounting principles ("U.S. GAAP") as follows:

(a) Under U.S. GAAP, for Securities and Exchange Commission registrants following full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of future income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10 percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Under Canadian GAAP, the Ceiling Test is calculated without application of a discount factor, but includes general and administration, management fees and interest expense.

Where the amount of a Ceiling Test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation, and amortization will differ in subsequent years. As at December 31, 2001, the application of the Ceiling Test under U.S. GAAP resulted in a write down of $744.3 million ($458.4 million after tax) of capitalized costs. At December 31, 2000 and 1999, the application of the Ceiling Test under U.S. GAAP did not result in a write down of capitalized costs. Under Canadian GAAP, the application of the Ceiling Test did not result in a write down for the years 2001, 2000 and 1999.

(b) SFAS 123, "Accounting for Stock-based Compensation", establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by SFAS 123, Enerplus has elected to continue to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25 ("APB 25"). Since all Unit Options and Trust Unit Rights were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income. Had compensation cost for Enerplus stock options been determined based on the fair market value at the grant dates of the awards consistent with methodology prescribed by SFAS 123, Enerplus net income (loss) and net income (loss) per Unit for years ended December 31, 2001, 2000 and 1999 would have been the pro forma amounts indicated below:

Years ended December 31, thousands except per Unit amounts	**2001**	2000	1999
Net income (loss):			
As reported under U.S. GAAP	**$ (261,288)**	$ 98,261	$ 48,024
Pro forma	**(262,191)**	$ 96,813	$ 46,627
Net income (loss) Per Unit			
Basic			
As reported under U.S. GAAP	**$ (4.76)**	$ 3.66	$ 2.34
Pro forma	**$ (4.78)**	$ 3.61	$ 2.27
Diluted			
As reported under U.S. GAAP	**$ (4.76)**	$ 3.65	$ 2.33
Pro forma	**$ (4.78)**	$ 3.60	$ 2.26

The estimated fair value of the options issued under the Unit Options Plan and the Trust Unit Right Incentive Plan was determined using the Black-Scholes model and the following assumptions:

	2001	2000	1999
Risk-free interest rate	**2.35%**	5.98%	5.07%
Estimated hold period prior to exercise	**3 years**	3 years	3 years
Volatility in the market price of the Trust Units	**24.5%**	33.5%	36.3%
Estimated monthly cash distributions	**$ 0.11/Unit**	$ 0.07/Unit	$ 0.05/Unit

As the exercise price of the rights is subject to downward revisions from time to time, the rights plan is a variable compensation plan under U.S. GAAP. Accordingly, compensation expense is determined as the excess of the market price over the exercise price of the rights at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. At December 31, 2001, no downward revision in exercise price had occurred and no compensation expense has been recognized for the rights. Due to the nature of the rights it is not possible to estimate the fair value of the rights.

(c) U.S. GAAP requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus certain other items not inlcuded in net income. The Fund's Comprehensive income is the same as its net income.

(d) Under U.S. GAAP the measurement date for acquisitions is the date the acquisition is announced. Under Canadian GAAP the measurement date for the acquisition is the closing date. Under U.S. GAAP, Unitholders' capital and property, plant and equipment has been increased by $37.3 million in 2001 and decreased by $7.8 million in 2000 for differences in the value of Trust Units issued to effect certain acquisitions.

(e) Effective January 1, 2000, the Fund adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for future income taxes and changed from the deferral method to the liability method. This liability method differs from U.S. GAAP due to the application of transitional provisions and the accounting for certain Canadian income tax credits and allowances. In 1999, under U.S. GAAP future income taxes and property, plant and equipment was increased by $4.5 million.

(f) Effective January 1, 2001, for U.S. reporting purposes, the Fund adopted Statement of Financial Accounting Standards ("SFAS") No. 133. "Accounting for Derivative Instruments and Hedging Activities". SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. There are no similar standards under Canadian GAAP.

Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs and requires that an entity formally document, designate and assess effectiveness of derivative instruments that receive hedge accounting treatment. The Fund has chosen to not formally document and designate its financial derivatives outstanding at December 31, 2001 and 2000 as hedges for U.S. GAAP purposes.

The application of U.S. GAAP would have the following effects on net income as reported:

($thousands except per Unit amounts)	**2001**	2000	1999
Net income as reported in the Consolidated Statement of Income	**$ 180,269**	$ 82,150	$ 25,754
Adjustments, net of applicable income tax			
Write-down of property, plant and equipment	**(458,474)**	-	-
Depletion, depreciation and amortization	**17,168**	16,111	22,270
Unrealized gain on financial derivatives	**(251)**	-	-
Net income (loss) and comprehensive income (loss)	**$(261,288)**	$ 98,261	$ 48,024
Net income (loss) per Unit			
Basic	**$ (4.76)**	$ 3.66	$ 2.34
Diluted	**$ (4.76)**	$ 3.65	$ 2.33
Weighted average number of Units outstanding			
Basic	**54,907**	26,841	20,532
Diluted	**54,956**	26,928	20,607

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

($thousands)	Canadian GAAP	Increase (decrease)	U.S. GAAP
December 31, 2001			
Financial derivative assets	$ -	$ 274	$ 274
Property, plant and equipment, net	2,178,316	(1,018,610)	1,159,706
Financial derivative liabilities	-	711	711
Future income taxes	333,560	(406,556)	(72,996)
Unitholders' capital	1,826,507	29,626	1,856,133
Accumulated income	324,570	(642,117)	(317,547)
December 31, 2000			
Property, plant and equipment, net	1,483,293	(339,588)	1,143,705
Future income taxes	353,115	(131,270)	221,845
Unitholders' capital	1,054,859	(7,758)	1,047,101
Accumulated income	144,301	(200,560)	(56,259)
December 31, 1999			
Property, plant and equipment, net	556,285	(359,183)	197,102
Future income taxes	33,593	(126,335)	(92,742)
Accumulated income	$ 78,328	$ (232,848)	$ (154,520)

5 YEAR DETAILED STATISTICAL REVIEW

The information contained in the table below reflects the reverse takeover of Enerplus by EnerMark on June 21, 2001 as required by Canadian generally accepted accounting principles.

($thousands, except per Unit amount)	**2001**	2000	1999	1998	1997
FINANCIAL					
Oil and gas sales	**$ 639,379**	$ 343,182	$ 169,541	$ 134,102	$ 173,919
Cash available for distribution	**$ 316,454**	$ 168,181	$ 78,189	$ 70,059	$ 97,165
Per Unit	**$ 5.67**	$ 5.49	$ 3.70	$ 3.70	$ 5.46
Net income	**$ 180,269**	$ 82,150	$ 25,754	$ 8,881	$ 23,855
Per Unit	**$ 3.28**	$ 3.06	$ 1.25	$ 0.47	$ 1.38
Capital expenditures, net of dispositions	**$ 152,216**	$ 65,844	$ 14,136	$ 56,516	$ 19,998
Total assets	**$ 2,284,253**	$ 1,567,952	$ 576,901	$ 617,881	$ 670,203
Bank debt, net of working capital	**$ 407,768**	$ 315,820	$ 142,066	$ 188,762	$ 111,170
Net debt/funds flow ratio	**1.2 x**	1.8 x	1.8 x	3.0 x	1.2 x

($ per BOE except percentage data)	**2001**	2000	1999	1998	1997
OIL AND GAS ECONOMICS					
Net royalty rate	**23%**	23%	19%	14%	18%
Weighted average price (net of hedging)	**$ 32.43**	$ 30.14	$ 18.32	$ 13.39	$ 17.22
Net royalty expense	**6.73**	7.10	3.47	1.87	3.11
Operating expense	**6.09**	4.83	4.02	4.04	3.95
Netback	**19.61**	18.21	10.83	7.48	10.16
General and administrative expense	**0.66**	0.63	0.62	0.56	0.45
Management fee	**0.47**	0.40	0.24	0.15	0.23
Interest expense, net of interest and other income	**0.85**	1.30	0.87	0.16	0.10
Capital taxes	**0.24**	0.26	0.17	0.20	0.18
Restoration and abandonment cash costs	**0.13**	0.13	0.12	0.10	0.03
Gain on sale of investment	**-**	-	0.06	0.03	-
Funds flow from operations	**$ 17.26**	$ 15.49	$ 8.75	$ 6.28	$ 9.17

COMBINED OPERATIONAL STATISTICS

The information contained in the table below reflects the combined results of Enerplus and EnerMark for the years indicated as if the combination of the Funds had been effective January 1, 1997. This information may not be representative of the actual results had the combination occurred on that date. No pro forma adjustments have been made to give effect to the combination of Enerplus and EnerMark for these periods. The information in this table is different from the financial statements and MD&A which account for the combination as a reverse takeover of Enerplus by EnerMark on June 21, 2001 as required by Canadian generally accepted accounting principles.

	2001	2000	1999	1998	1997
OPERATING					
Production					
Crude oil per day (bbls)					
Enerplus	**7,156**	6,029	5,522	5,901	5,361
EnerMark	**16,854**	12,089	11,416	12,033	12,805
Combined	**24,010**	18,118	16,938	17,934	18,166
NGLs per day (bbls)					
Enerplus	**1,405**	1,284	1,173	1,307	1,325
EnerMark	**3,245**	2,111	1,980	2,296	2,041
Combined	**4,650**	3,395	3,153	3,603	3,366
Natural Gas per day (Mcf)					
Enerplus	**56,861**	48,143	47,590	49,723	48,936
EnerMark	**146,866**	101,473	71,713	78,559	76,893
Combined	**203,727**	149,616	119,303	128,282	125,829
BOE per day					
Enerplus	**18,038**	15,337	14,627	15,495	14,842
EnerMark	**44,577**	31,112	25,348	27,422	27,662
Combined	**62,615**	46,449	39,975	42,917	42,504

Established Reserves (proven and 50% of probable)					
Crude oil (Mbbls)					
Enerplus	-	49,375	29,263	32,441	25,724
EnerMark	-	72,739	56,408	57,125	51,984
Combined	**113,668**	122,114	85,671	89,566	77,708
NGLs (Mbbls)					
Enerplus	-	5,766	4,518	4,510	5,308
EnerMark	-	12,930	8,857	10,634	11,108
Combined	**18,451**	18,696	13,375	15,144	16,416
Natural Gas (MMcf)					
Enerplus	-	338,760	270,077	230,427	210,874
EnerMark	-	747,182	509,554	384,745	396,083
Combined	**1,081,478**	1,085,942	779,631	615,172	606,957
MBOE					
Enerplus	-	111,601	78,794	75,356	66,178
EnerMark	-	210,199	150,191	131,883	129,106
Combined	**312,365**	321,800	228,985	207,239	195,284
Established reserve life index (years) BOE Combined (1)	**14.0**	13.7	13.5	14.2	12.6

(1) The established Reserve Life Index (RLI) is based upon year end established reserves divided by following year production volume estimates.

INCOME TAX - CANADIAN RESIDENTS (CDN$/UNIT)

EnerMark Income Fund

The following table outlines the breakdown of cash distributions per Unit paid or payable by EnerMark Income Fund during the period February 10, 2001 up to and including June 10, 2001, for Canadian Income Tax purposes. On June 21, 2001 EnerMark and Enerplus merged together and continued under the name of Enerplus Resources Fund. Each EnerMark Unitholder received 0.173 of an Enerplus Trust Unit in exchange for each EnerMark Trust Unit. Unitholders of EnerMark, who exchanged their EnerMark Trust Units for Enerplus Trust Units, should have received the cash distributions paid or payable by Enerplus for the period July 10, 2001 up to and including December 31, 2001, for Canadian Income Tax purposes. Refer to Enerplus cash distributions for the period July 10, 2001 up to and including December 31, 2001.

Record Date	Payment Date	Total Distribution Paid	Taxable Income Amount	Taxable Dividend Amount	Return of Capital Amount
Feb. 10	Feb. 20	$0.1300	$0.1125	$0.0037	$0.0138
Mar. 10	Mar. 20	0.0900	0.0767	0.0037	0.0096
Apr. 10	Apr. 20	0.0900	0.0767	0.0037	0.0096
May 10	May 20	0.1700	0.1483	0.0036	0.0181
June 10	June 20	0.0900	0.0767	0.0037	0.0096
Total per Unit		**$0.5700**	**$0.4909**	**$0.0184**	**$0.0607**

Enerplus Resources Fund

The following table outlines the breakdown of cash distributions per Unit paid or payable by Enerplus Resources Fund during the period January 10, 2001 to December 31, 2001 for Canadian Income Tax purposes.

Record Date	Payment Date	Total Distribution Paid	Taxable Income Amount	Taxable Dividend Amount	Return of Capital Amount
Pre Merger					
Jan. 10	Jan. 20	$0.4000	$0.3344	-	$0.0656
Feb. 10	Feb. 20	0.6500	0.5434	-	0.1066
Mar. 10	Mar. 20	0.4500	0.3762	-	0.0738
April 10	April 20	0.4500	0.3762	-	0.0738
May 10	May 20	0.9000	0.7524	-	0.1476
June 10	June 20	0.5200	0.4347	-	0.0853
July 10	July 20	0.4800	0.3033	0.0122	0.1645
Post Merger					
Aug. 10	Aug. 20	0.5000	0.3165	0.0120	0.1715
Sept. 10	Sept. 20	0.4500	0.2836	0.0121	0.1543
Oct. 10	Oct. 20	0.4000	0.2508	0.0121	0.1371
Nov. 10	Nov. 20	0.4000	0.2508	0.0121	0.1371
Dec. 10	Dec. 20	0.3500	0.2187	0.0113	0.1200
Dec. 31	Jan. 20	0.3000	0.1859	0.0113	0.1028
Total per Unit		**$6.2500**	**$4.6269**	**$ 0.0831**	**$1.5400**

INCOME TAX - UNITED STATES RESIDENTS (US$/UNIT)

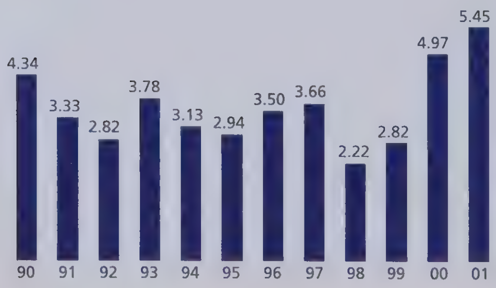
Enerplus Resources Fund

The following table outlines the breakdown of cash dividends paid per Unit by Enerplus Resources Fund, prior to any amounts deducted for Canadian withholding tax, for Units held through a broker or other intermediary for the period January 20 to December 20, 2001 for U.S. income tax purposes. All amounts shown are in U.S. dollars as converted on the applicable payment date.

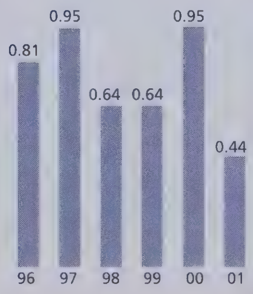
Record Date	Payment Date	Total Distributions Paid in US$	Taxable Ordinary Dividends	Non-Taxable Return of Capital
Jan. 10	Jan. 20	$ 0.265023	$ 0.231365	$ 0.033658
Feb. 10	Feb. 20	0.422626	0.368952	0.053674
Mar. 10	Mar. 20	0.288000	0.251424	0.036576
April 10	April 20	0.286807	0.250382	0.036425
May 10	May 20	0.582939	0.508905	0.074034
June 10	June 20	0.338541	0.295546	0.042995
July 10	July 20	0.310277	0.270872	0.039405
Aug. 10	Aug. 20	0.323164	0.282122	0.041042
Sept. 10	Sept. 20	0.286168	0.249825	0.036343
Oct. 10	Oct. 20	0.253132	0.220984	0.032148
Nov. 10	Nov. 20	0.251098	0.219208	0.031890
Dec. 10	Dec. 20	0.221659	0.193508	0.028151
Total per Unit		**$ 3.829434**	**$ 3.343093**	**$ 0.486341**

HISTORICAL ANNUAL CASH DISTRIBUTIONS

Enerplus Cash Distributions
CDN$ per Unit



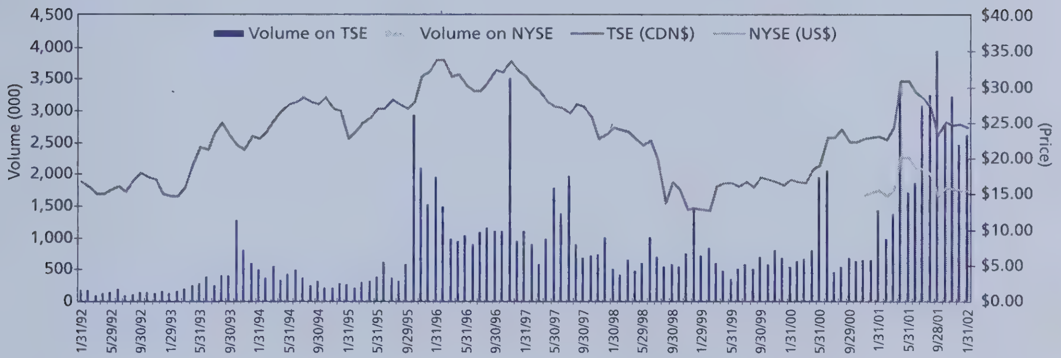
EnerMark Cash Distributions
CDN$ per Unit



UNIT TRADING INFORMATION

ENERPLUS RESOURCES FUND

Trading Symbols:
TSE: ERF.un
NYSE: ERF



ERF.un Trading Information on TSE as at December 31,

CDN$	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
High	$31.50	18.60	25.20	30.00	33.00	35.25	33.00	25.50	19.20	24.60	32.86
Low	12.60	13.56	13.50	22.20	21.60	28.50	20.40	12.00	12.60	15.60	22.00
Close	14.10	15.00	23.10	27.00	32.25	32.40	23.40	12.96	16.32	22.90	24.75
Volume 000	3,112	1,680	5,079	4,245	9,898	16,160	12,672	8,230	7,322	10,214	29,466

Enerplus Resources Fund began trading on the New York Stock Exchange November 17, 2000.

ERF Trading Information on NYSE as at December 31,

US$	2000	2001
High	15.25	23.50
Low	14.69	13.79
Close	15.25	15.56
Volume 000	121	19,740

DISTRIBUTION REINVESTMENT PLAN

Enerplus Resources Fund has a convenient method of reinvesting cash distributions or investing additional funds into new Trust Units. Residents of Canada who hold at least one Trust Unit, are eligible to participate in the Plan.

Features of the Plan Include:

- New Units purchased monthly through the distribution reinvestment plan are purchased at a 5% discount;
- Optional cash payments of up to $5,000 monthly may be made to purchase new Units at the average market price regardless of whether monthly distributions are being reinvested;
- No service charges or brokerage fees are incurred by Unitholders and all administrative costs of the Plan are borne by the Fund;
- Participants will receive regular statements regarding their purchases.

If your Units are held for you by your broker, investment dealer or other financial intermediary, you must direct that company to enrol your Units into the Plan.

You can make an optional cash payment when enrolling in the Plan by enclosing a cheque or money order payable to "CIBC Mellon Trust Company" with the completed authorization form.

To obtain more information and/or enrolment forms, please contact Enerplus' Investor Relations Department at 1-800-319-6462, in Calgary at (403) 298-2200, by fax at (403) 298-2211 or by Email at investorrelations@enerplus.com.

ENERPLUS INTERNET SITE

Enerplus Resources Fund has a comprehensive website that provides investors with an immediate source of all public information. The following documents are available at www.enerplus.com:

- Unit Trading Information
- Annual and Quarterly Reports
- Tax Information
- News Releases
- Recent Presentations
- 15 Minute Delayed Stock Quote
- Historical Distribution Tables
- Distribution Reinvestment and Unit Purchase Plan
- Adjusted Cost Base calculator
- Important Dates and Events

ANNUAL GENERAL AND SPECIAL MEETING

Unitholders are encouraged to attend Enerplus Resources Fund Annual General and Special Meeting being held on:

Thursday, April 25, 2002

at 10:00 AM, local time,

at Western Canadian Place

700 - 9th Avenue S.W.

Conference Rooms A & B, Plus 30 Level

Calgary, Alberta

Those unable to attend are asked to sign and return the Form of Proxy mailed with this annual report.

DIRECTORS

Douglas R. Martin [3] [4] [5]
President
Charles Avenue Capital Corp.
Calgary, Alberta

André Bineau [1]
Vice President, Association de bienfaisance et de retraite des policiers et policières de la ville de Montréal
Montréal, Québec

Derek J.M. Fortune [3] [4]
Secretary/Manager, Superannuation Fund
City of Ottawa
Ottawa, Ontario

Gordon J. Kerr [4]
President & Chief Executive Officer
Enerplus Global Energy Management Company
Calgary, Alberta

Arne R. Nielsen [2]
Chairman,
Shiningbank Energy Management Inc.
Calgary, Alberta

Robert L. Normand [1] [3]
Corporate Director
Montréal, Québec

Eric P. Tremblay [2]
Senior Vice President, Capital Markets
Enerplus Global Energy Management Company
Calgary, Alberta

Harry B. Wheeler [1] [2]
President,
Colchester Investments Ltd.
Calgary, Alberta

Robert L. Zorich
Managing Director,
EnCap Investments L.C.
Houston, Texas

[1] Audit & Risk Management Committee
[2] Environment, Safety & Reserves Committee
[3] Corporate Governance Committee
[4] Compensation & Human Resources Committee
[5] Chairman of the Board

OFFICERS

Gordon J. Kerr
President & Chief Executive Officer

Robert J. Waters
Senior Vice President & Chief Financial Officer

Heather J. Culbert
Senior Vice President, Corporate Services

Garry A. Tanner [6]
Senior Vice President, New Business Development

Eric P. Tremblay
Senior Vice President, Capital Markets

Jo-Anne M. Caza
Vice President, Investor Relations

Daryl W. Cook
Vice President, Operations

Dorothy J. Else
Vice President, Land

Wayne T. Foch
Vice President, Finance

I. Laura Pierrot
Vice President & Treasurer

Darrell E. Shaw
Vice President, Exploitation

Gerald F. Stevenson
Vice President, Acquisitions

Christina S. Meeuwsen
Corporate Secretary

Wayne G. Ford
Controller

Joanne M. Danyschuk
Assistant Corporate Secretary

[6] Officer of Enerplus Global Energy Management Company only

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS RESOURCES FUND

EnerMark Inc.

Enerplus Resources Corporation

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta and Toronto, Ontario

AUDITORS

Arthur Andersen LLP
Calgary, Alberta

TRANSFER AGENT

The CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1-800-387-0825
Email: inquiries@cibcmellon.com

CO-TRANSFER AGENT

Mellon Investor Services L.L.C.
Ridgefield, New Jersey

INDEPENDENT RESERVE ENGINEERS

Sproule Associates Limited
Calgary, Alberta

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

New York Stock Exchange:	ERF
Toronto Stock Exchange:	ERF.un

HEAD OFFICE

Western Canadian Place
1900, 700 - 9th Avenue S.W.
Calgary, Alberta T2P 3V4

Telephone:	(403) 298-2200
Toll free:	1-800-319-6462
Fax:	(403) 298-2211
Email:	investorrelations@enerplus.com

Change of address effective June 1, 2002

The Dome Tower
3000, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

For more information visit our web site:
www.enerplus.com

Abbreviations

AECO	Alberta Energy Company interconnect with the Nova System
ARTC	Alberta Royalty Tax Credit
bbl	barrel
bbl/day	barrel(s) per day
Bcf	billion cubic feet
BOE(s)	barrel of oil equivalent (6 Mcf gas = 1 bbl crude oil)
BOE/day	barrel of oil equivalent per day
E&P	exploration and production
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMbtu	million British thermal units
MMcf	million cubic feet
MMcf/day	million cubic feet per day
NYSE	New York Stock Exchange
RLI	reserve life index
TSE	Toronto Stock Exchange
WI	percentage working interest of ownership
WTI	West Texas Intermediate at Cushing, Oklahoma

www.enerplus.com